CSI RD&D4 Final Project Webinar: Analysis to Inform CA Grid Integration Rules for PV

Advanced Inverter Settings for Improving Integration of PV into Transmission and Distribution

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Webinar Agenda

- Project Overview
- Distribution
  - Development of advanced inverter settings
  - Application of settings to utility feeders
- Transmission
  - Study Method & Assumptions
  - Results
- Conclusions

Industry Landscape

In many cases, use of smart inverters can be the least-cost solution for integration issues

Benefit

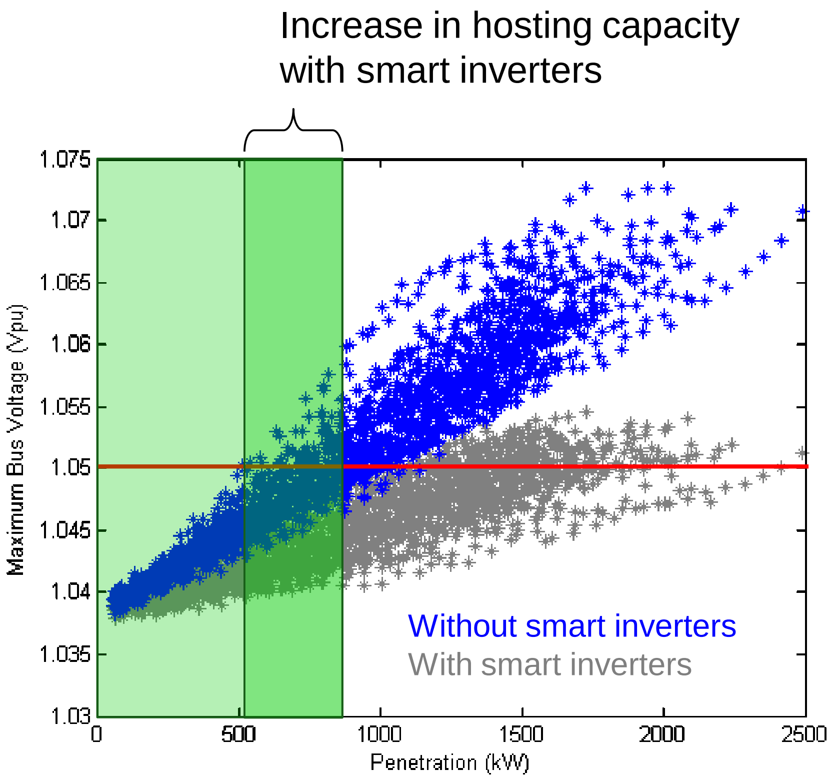
- Smart inverters have inherent capabilities that can improve the integration of solar PV
- Due to flexibility of advanced inverters, many options/settings are available

Challenge

- Sheer number of PV systems interconnecting
- Limited bandwidth for detailed engineering studies

Solution

- Effective default settings
- Straightforward means for determining effective situation-specific settings



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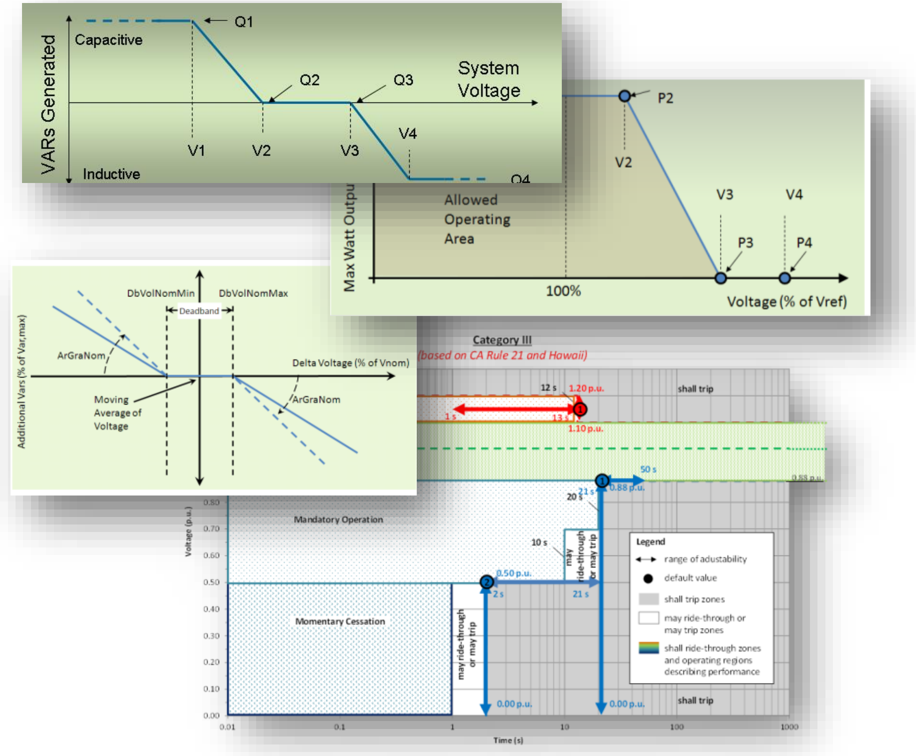
Project Overview

Objective

- Ease the use of advanced inverters for utility engineers
- Maximize capabilities of smart inverters to improve solar PV integration
- Recommend settings for smart inverter functions considered in Rule 21

Approach

- Utilize advanced inverter controls modeled in OpenDSS and PSLF to analyze range of distribution and transmission systems/configurations, DER locations, and DER penetration levels
- Evaluate methods for determining appropriate settings
- Evaluate default settings
- Determine overall effectiveness and grid impact



- **Team:**

with support from SCE, SDG&E, PG&E, CAISO, PJM

Specific Issues Being Addressed

- Both simple and advanced methods for determining most effective smart inverter settings that provide the maximum benefit based upon feeder characteristics, DER deployments and DER locations
- Identifying locations where advanced inverter controls are most effective – and when they're not
- Evaluating default volt-var settings that are applicable across a wide range of potential conditions.
- Evaluating proposed default settings
  - IEEE 1547 proposed Volt/var control curves
  - CA Rule 21 Voltage/frequency ride-through

Inverter Functions Considered

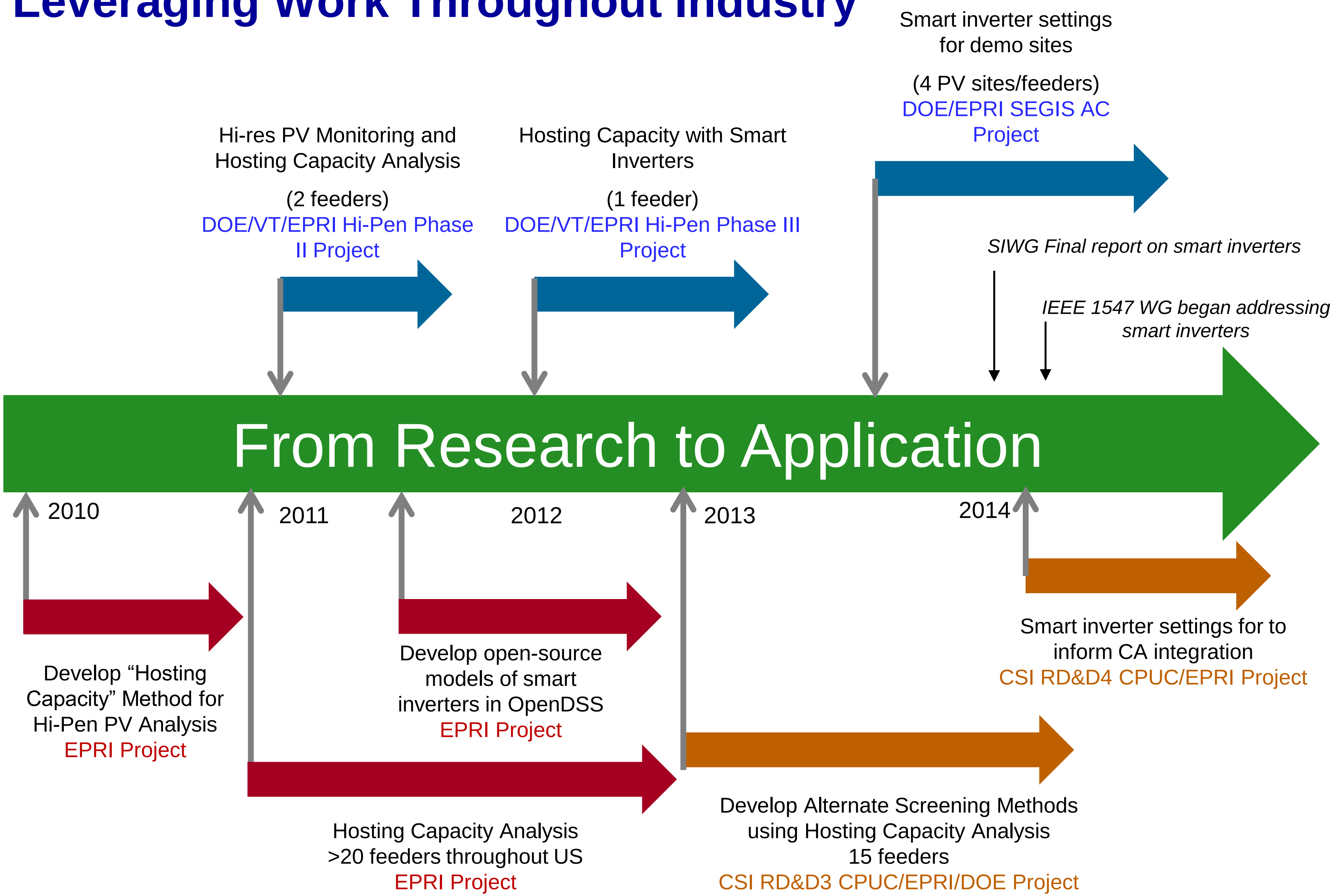
Distribution-centric

- Power factor control
- Volt-var control
- Volt-watt control
- Control combinations

Transmission-Centric

- Voltage ride-through
- Frequency ride-through

Leveraging Work Throughout Industry



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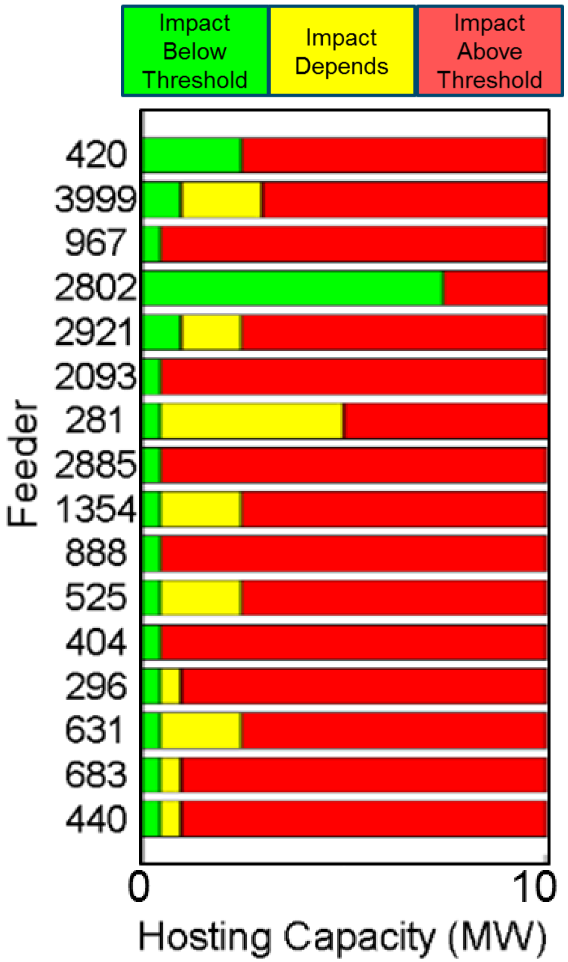
Leveraging Efforts from CSI RD&D3 Project

CSI RD&D 3: What did we Do?

**Alternatives to the 15% Rule: Final Project Summary*. EPRI, Palo Alto, CA: 2015. 3002006594.

Modeling and Hosting Capacity Analysis

- Clustering analysis to determine "range" of distribution feeders
- ~ 20 feeders selected across all three IOU's
- Detailed feeder models developed in OpenDSS
- Hosting capacity analysis performed on selected feeders*



Application to this project

- Utilized feeder models previously developed
- Selected feeders based upon PV impacts (hosting capacity)
- Applied same hosting capacity methods used in RD&D3

Distribution Requirements for Smart Inverters

- Purpose
  - Develop recommended configuration/implementation options for smart inverters to better integrate solar PV into distribution
    - Determine recommended smart inverter settings
    - Evaluate hosting capacity impacts with Smart Inverter Settings
- Approach
  - Evaluate a range of feeder configurations, penetration levels, and potential inverters with existing feeder controls to develop default settings/parameters
  - Includes curves (set points), inverter ratings, response times for:
    - Fixed power factor
    - Volt-watt
    - Volt-var

Bulk System Requirements for Smart Inverters

- Purpose
  - Evaluate effectiveness of proposed Rule 21 ride-through settings
- Approach
  - Modify WECC transmission model to evaluate smart inverter function impact on FIDVR (fault-induced delayed voltage recovery) and frequency performance under a range of transmission faults (events).
  - Ride through characteristics considered
    - Voltage ride-through
    - Frequency ride-through

Project Partners

SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL Company
San Onofre Nuclear Generating Station

PG&E Pacific Gas and Electric Company®

SDG&E
A Sempra Energy utility℠

Sandia National Laboratories

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

SunShot
U.S. Department of Energy

PUBLIC UTILITIES COMMISSION
EUREKA
STATE OF CALIFORNIA

GO solar CALIFORNIA

Itron

High-Level Key Takeaways

Distribution Focus

- Optimizing smart inverter settings can be complex
- Many settings are feeder and/or location dependent
- Inverter "headroom" for providing reactive power control at full output is critical
- Default settings can be found that improve integration of PV
- Simplified approaches for determining appropriate settings can be applied

Transmission Focus

- Rule 21 proposed ride-through characteristics improve integration of PV
- System response improved when compared to PV w/o ride-through
- Initial results indicate use of dynamic reactive power can further improve integration

Inverter Settings for Distribution System Performance

Power Factor, Volt-var, Volt-watt

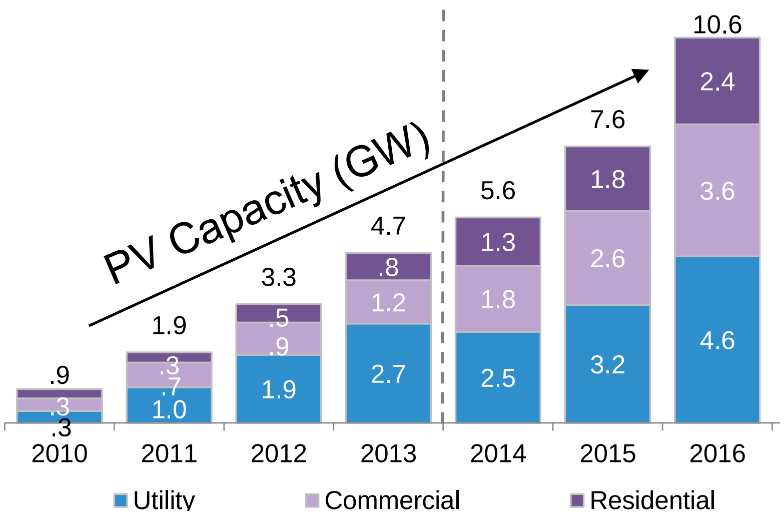
Industry Challenge and Distribution Focused Project Goal

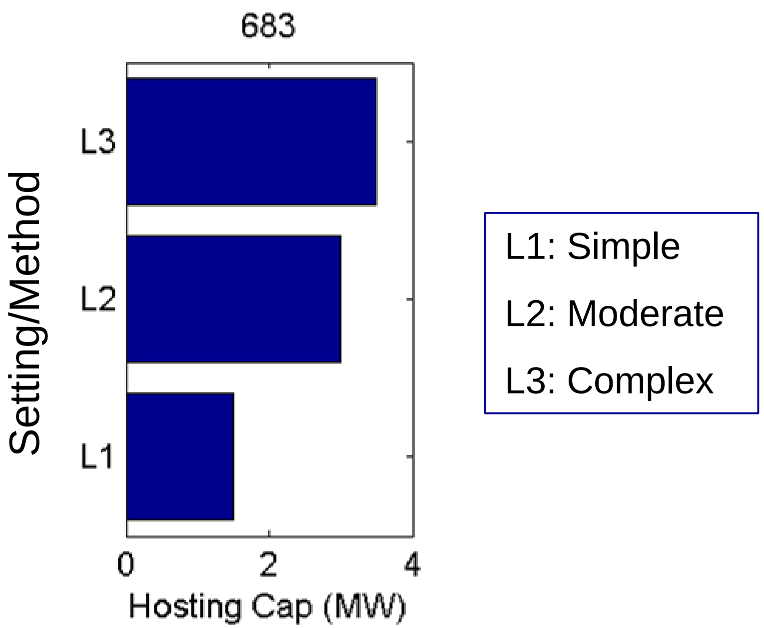
Industry Challenge

- Landscape is changing
  - New distributed resources
- New challenges for utilities
  - How to accommodate more PV
  - **How to use advanced inverters**

Project Goal

- Determine advanced inverter settings to accommodate more PV (without system upgrades)
  - Power factor, volt-var, volt-watt
  - Settings and/or methods to determine settings





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Approach to Derive Recommended Settings

Develop Methods to Derive Settings

Select Test Feeders

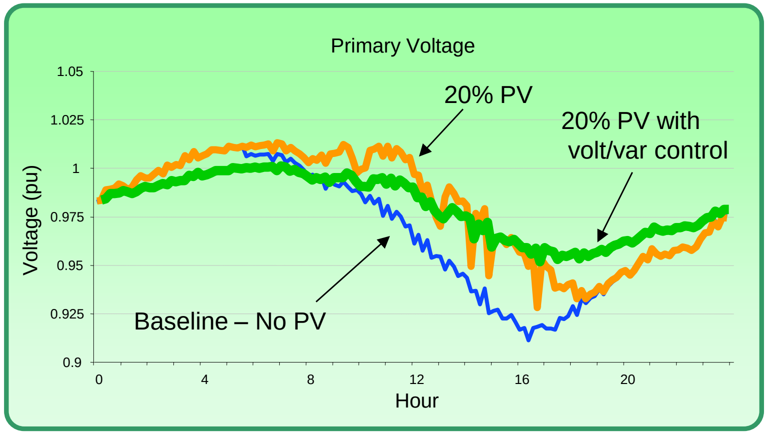
Apply Methods and Determine Feeder Impact based on Hosting Capacity

Development of Advanced Inverter Settings

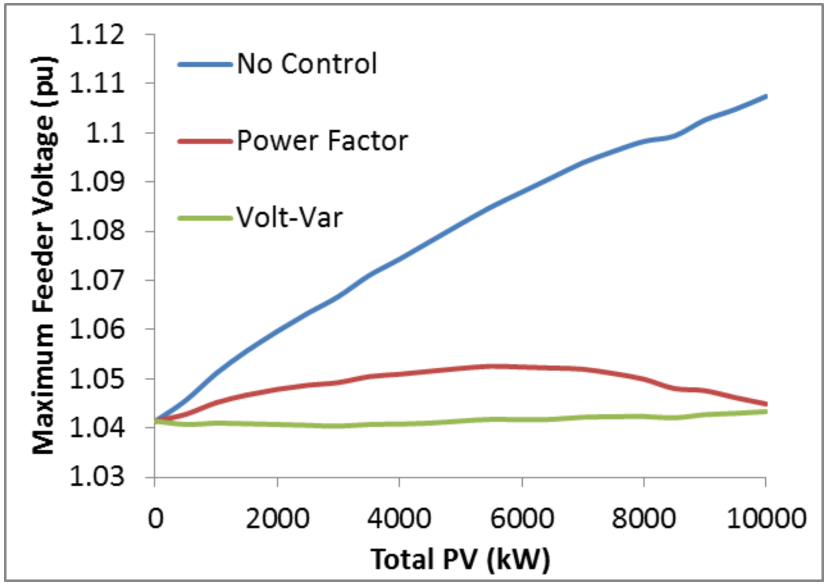
Advanced Inverters Can Have Significant Advantages

Advanced inverters can improve integration of DER by reducing some of the adverse impacts from DER.

- Mitigate voltage issues
- Provide least-cost solution
- Increase hosting capacity



24 Hour Simulation



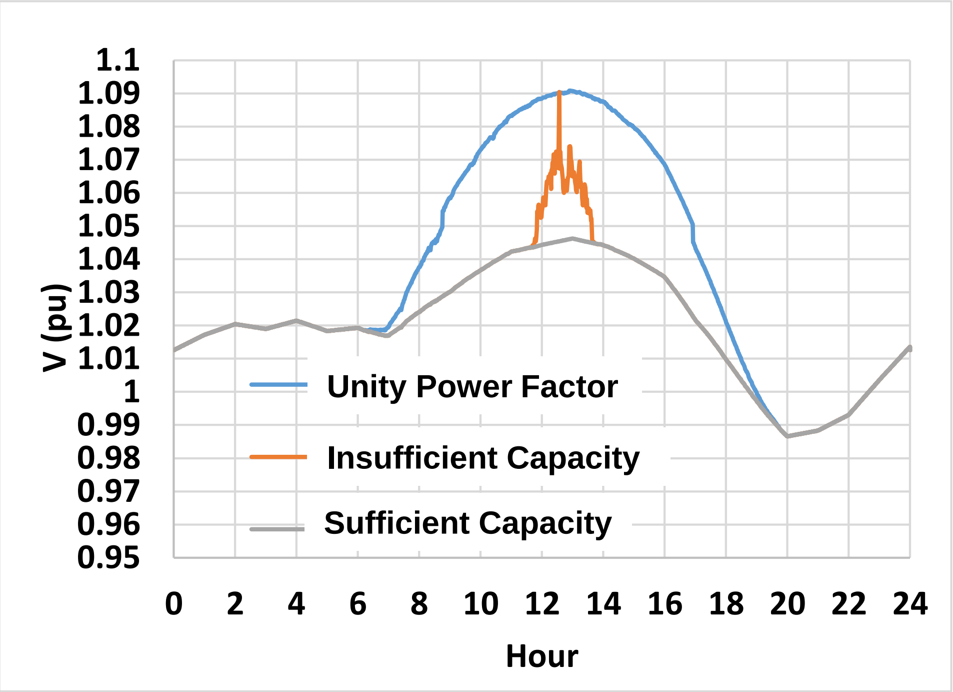
Importance of Reactive Power Capacity

Issue:

- Any reactive power (var) related inverter function used to mitigate adverse voltage impacts from DER requires sufficient inverter capacity.
- Without sufficient inverter capacity, benefits from use of reactive power (and possible increase in hosting capacity) are eliminated (reactive isn't available when needed most – at full output)

Solutions:

- DER providing a minimum of +/- 0.9 power factor at full output allows for sufficient inverter var control
- Allow inverters to operate where reactive power output is a priority over active power output



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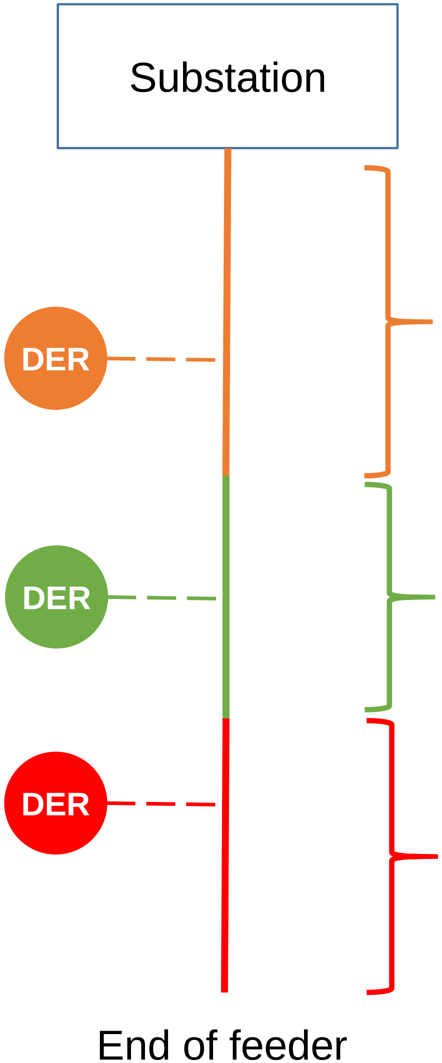
Location Does Matter



Single DER System and Location

Region A

Var control may not be needed due to minimal voltage rise caused by DER

High X/R ratio
High short-circuit strength
DER doesn't move voltage
Reactive power control not needed

Region B

Var control most effective due to high X/R

High X/R ratio
Low short-circuit strength
DER moves voltage
Reactive power control is effective

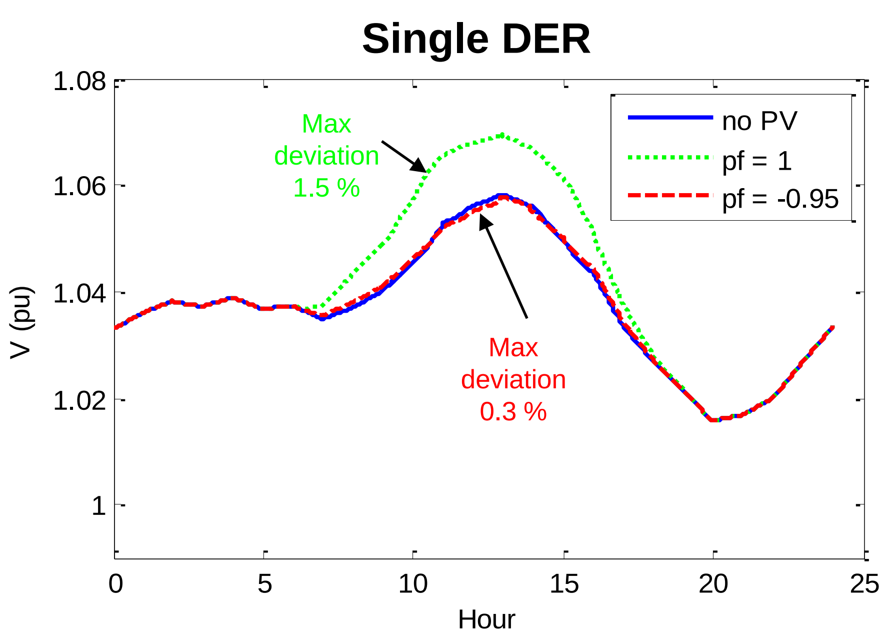
Region C

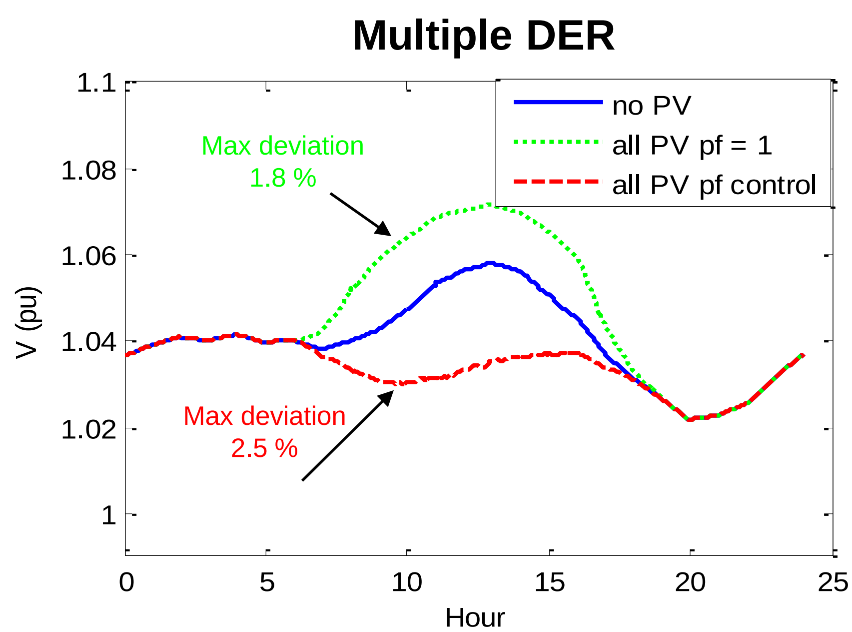
Var control not as effective due to low X/R

Low X/R ratio
Low short-circuit strength
DER moves voltage
Reactive power control is not as effective

Multiple Inverters add Complexity

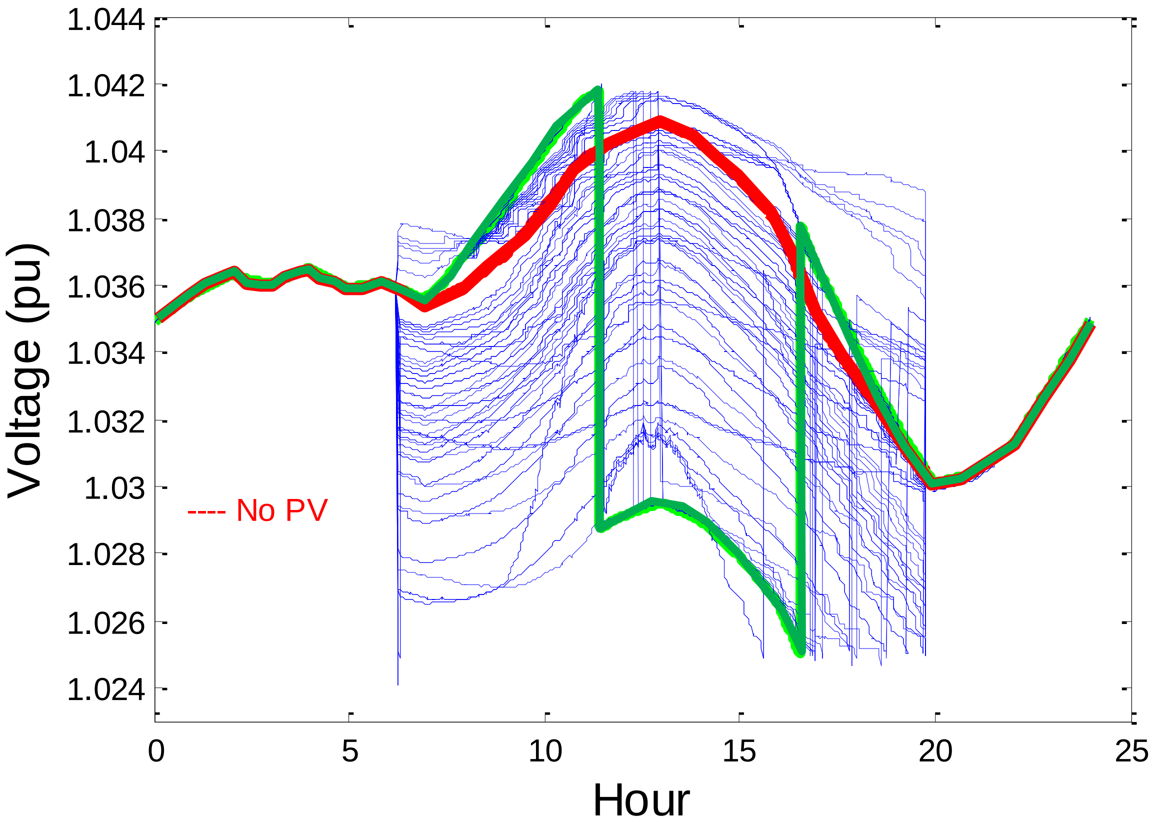
- Easily calculated for a single inverter on a feeder
- Settings need to be properly tuned for the multiple inverter scenario





Many Possible Inverter Settings

- There are numerous possible inverter settings
- Wrong settings can actually worsen grid performance



Blue lines indicate voltage response using different volt-var settings.

Discrete voltage changes are due to capacitor switching or inverter status change.

Methods to Derive Inverter Settings

Level	Complexity	Power Factor	Volt-var	Volt-watt
0	None	Unity Power Factor	Disabled, Unity Power Factor	Disabled, Unity Power Factor
1	Low	Based on Feeder X/R Ratio	Generic Setting	Generic Setting
2	Medium	Based on Feeder Model and PV Location	Based on Feeder Model and PV Location	Not Applied
3	High	Based on Feeder Model and PV Location	Based on Feeder Model, PV Location, and Service Transformer Impedance	Not Applied

Power Factor Control

- Level 1 settings:
  - Simple method required to determine settings
  - Setting is feeder specific, one power factor setting per feeder
  - Setting is based on the Mean X/R ratio on the feeder

Level	Method	Data Requirements	Power Factor Setting
1	**Mean X/R Ratio of all 3-phase MV nodes to determine power factor**	Primary node X/R ratios on feeder, number of phases at each node	Single Setting on each feeder

$$Power\ factor \cong \frac{\left({}^{X}\!/_{R}\right)_{mean}}{\sqrt{\left(\left({}^{X}\!/_{R}\right)_{mean}\right)^{2}+1}}$$

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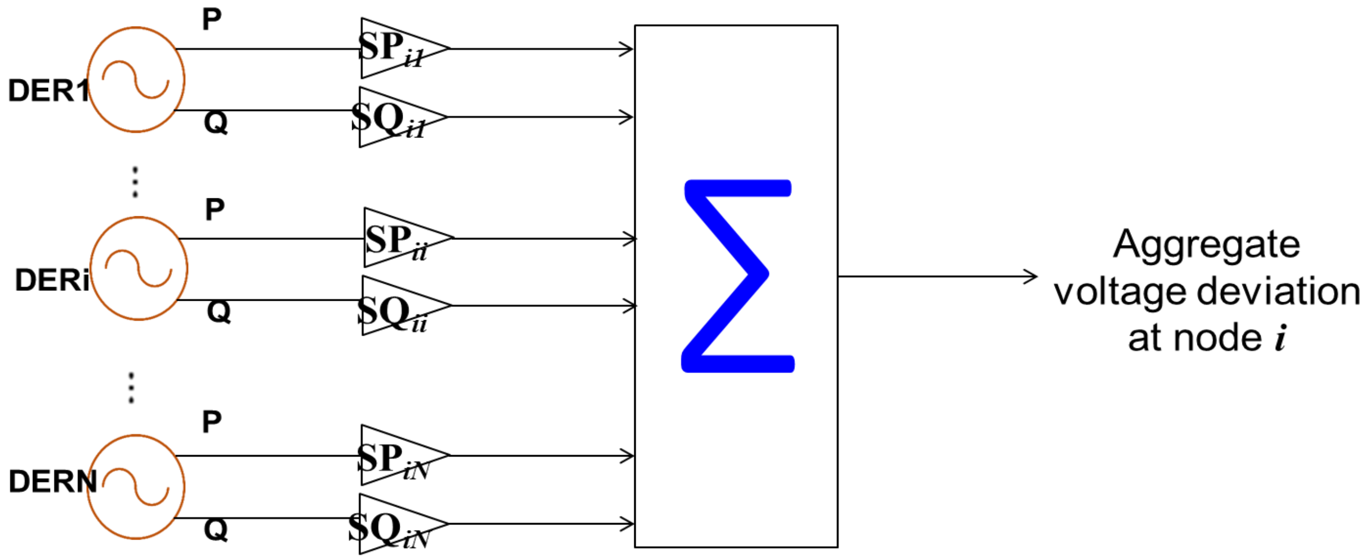
Power Factor Control

- Level 3 settings:
  - Sensitivity-based optimization
  - Each PV has unique power factor



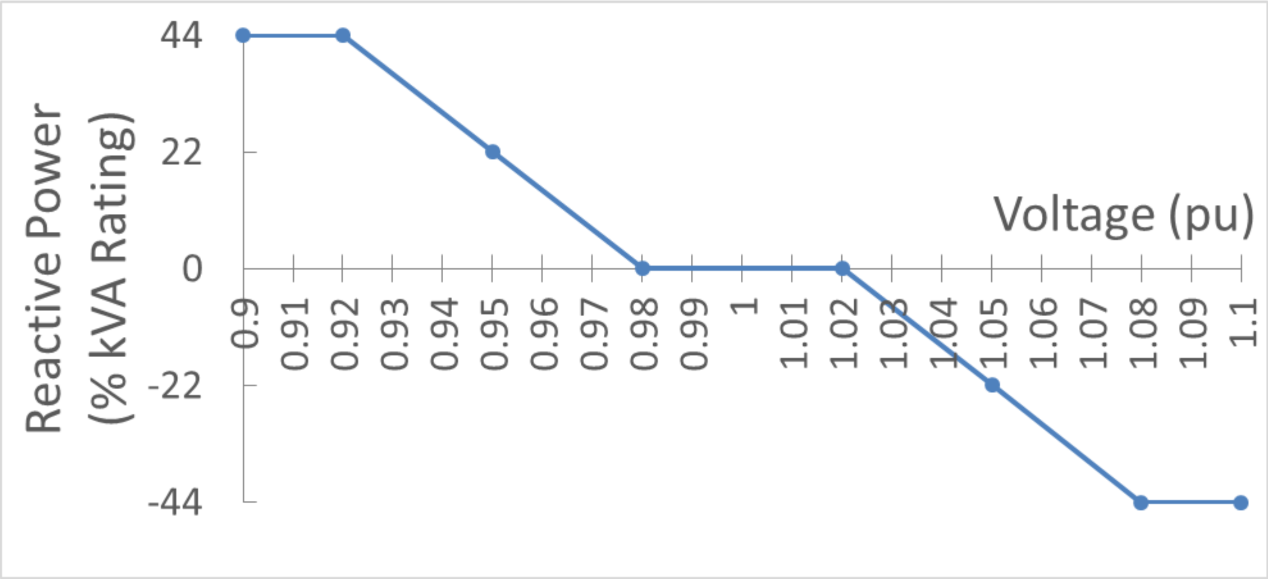
$$\Delta V_i = (SP_{i1}P_1 + SQ_{i1}Q_1) + (SP_{i2}P_2 + SQ_{i2}Q_2) + \cdots (SP_{iN}P_N + SQ_{iN}Q_N)$$

Objective: $min \sum_{i=1}^{N} \Delta V_i^2$

Volt-var Control

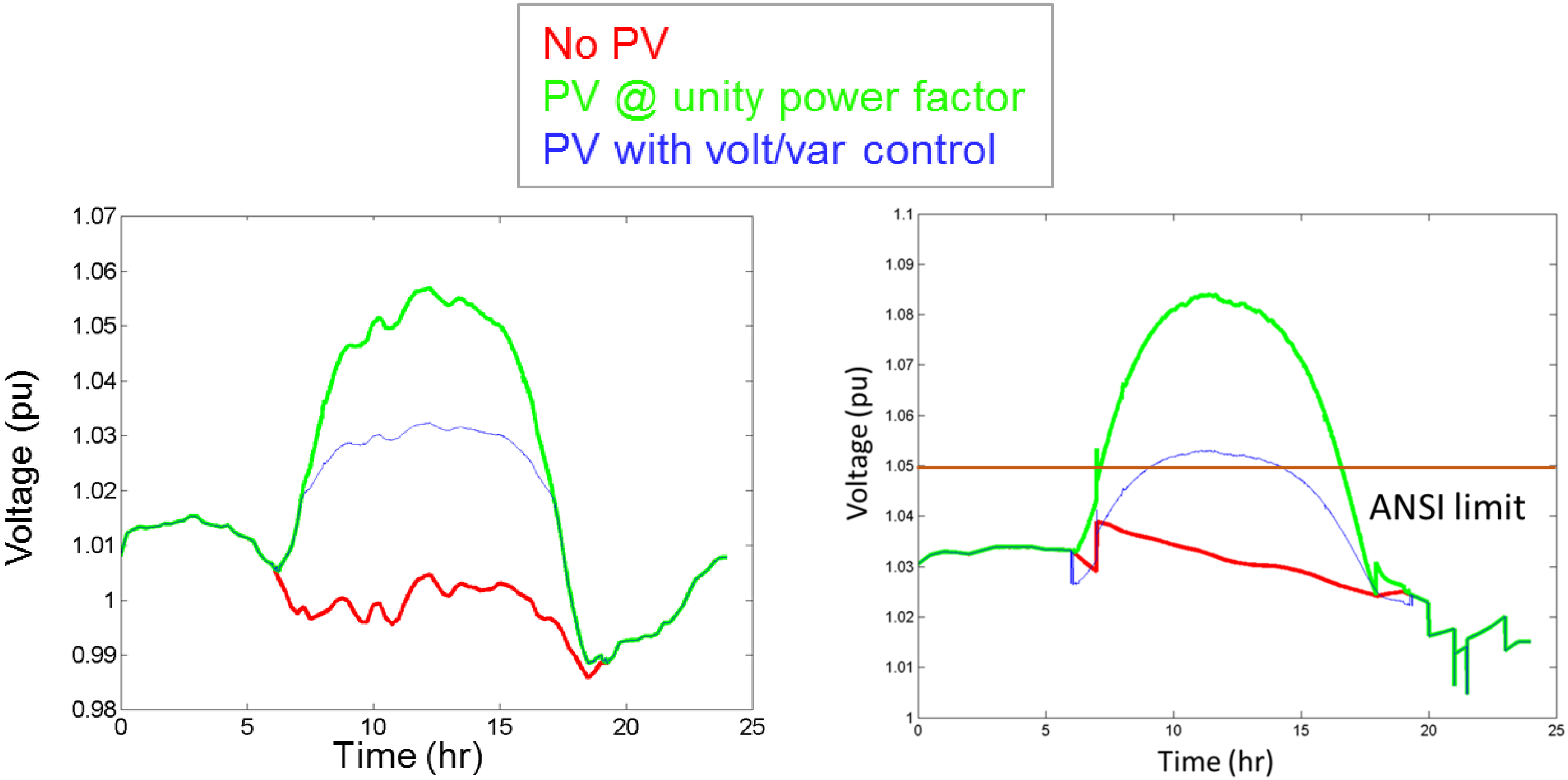
**Analysis to Inform CA Grid Integration: Methods and Default Settings to Effectively Use Smart Inverter Functions in the Distribution System.* EPRI, Palo Alto, CA: 2015. 3002007139.

- Level 1 settings*:
  - Wide bandwidth (does nothing when within 2% from nominal)
  - Maximum reactive power output equivalent to 90% power factor when real power is at full output (assumed that the inverter is 10% larger than the PV system rating)



Same settings as proposed within P1547 WG. Analysis performed here confirmed effectiveness and no adverse impact

Time-series Response on a Clear Day



Volt-var control with the default setting reduce overvoltage.

The non-aggressive slope of the volt-var control limits the reactive power output.

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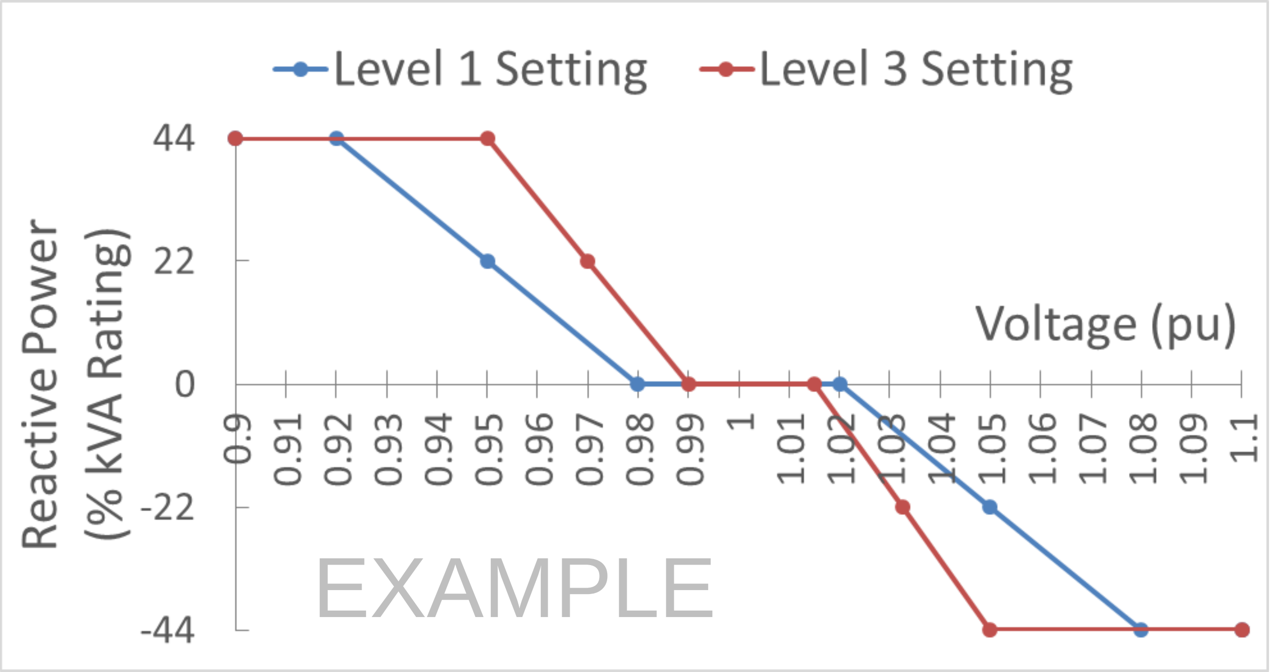
Volt-var Control

- Level 3 settings:
  - A slight modification to the Level 1 setting
  - Adjusted based on interconnection transformer
  - Targeted control of the medium voltage node



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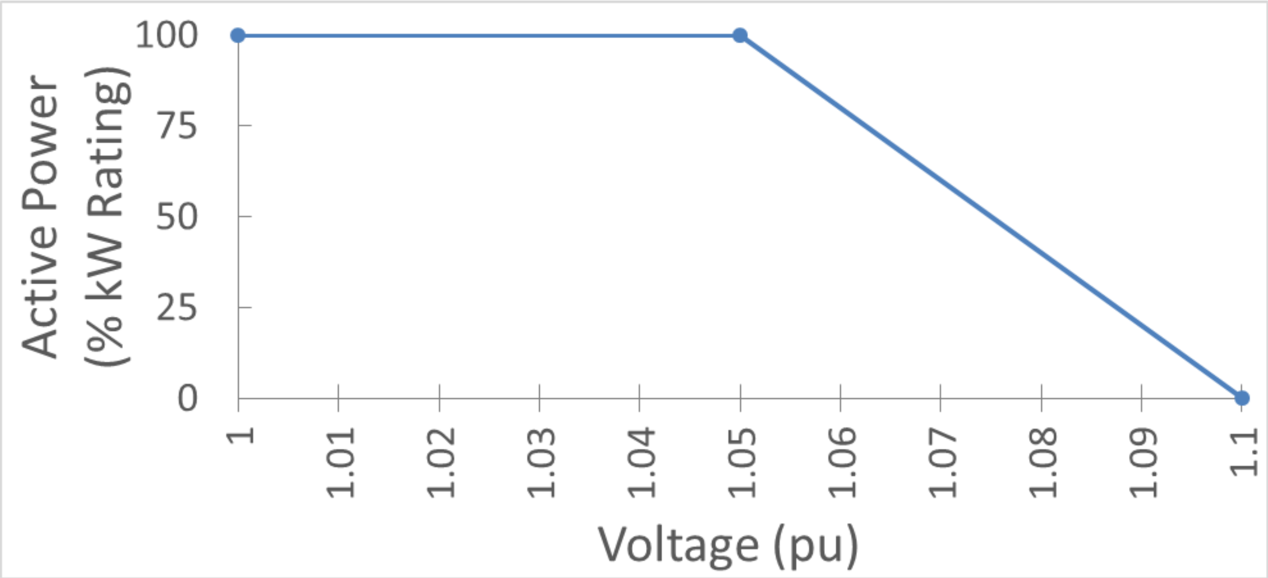
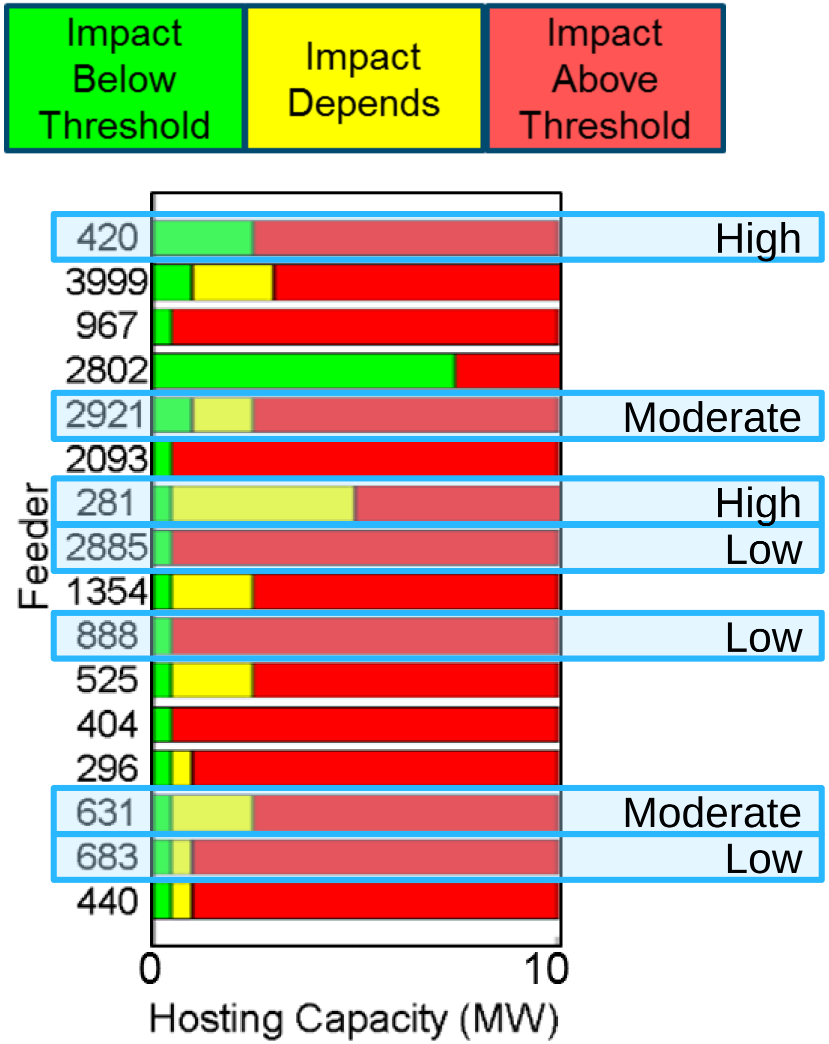
Volt-watt Control

- Level 1 settings:
  - Delayed control (does not curtail power when voltage is within ANSI limits)
  - Reactive power control functions should be utilized before the inverter voltage reaches the ANSI limit
  - Active power curtailed to Zero at 1.1pu voltage



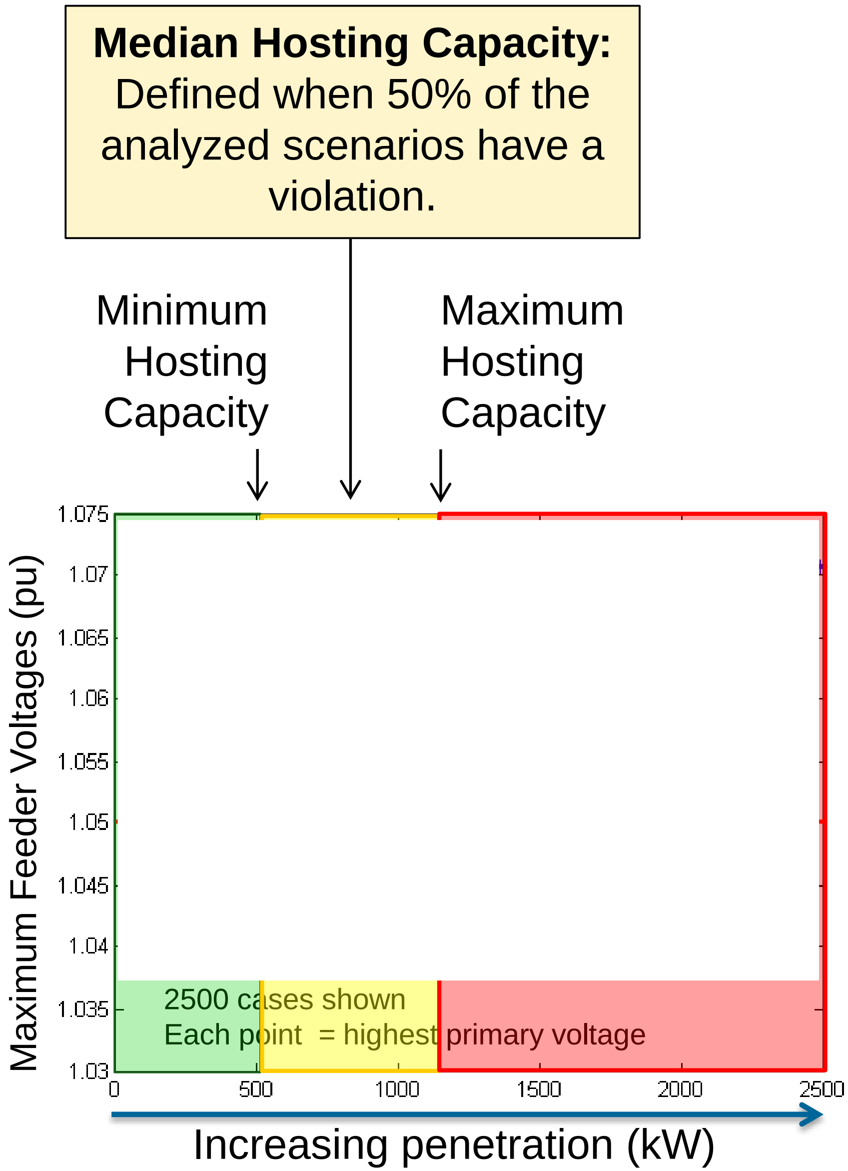
Application of Settings to Utility Feeders

Feeders Selected from Previous CSI3 Analysis*



*CPUC-CSI3 *Alternatives to the 15% Rule: Final Project Summary*. EPRI, Palo Alto, CA: 2015. 3002006594.

Hosting Capacity – Explanation



No observable violations regardless of size/location

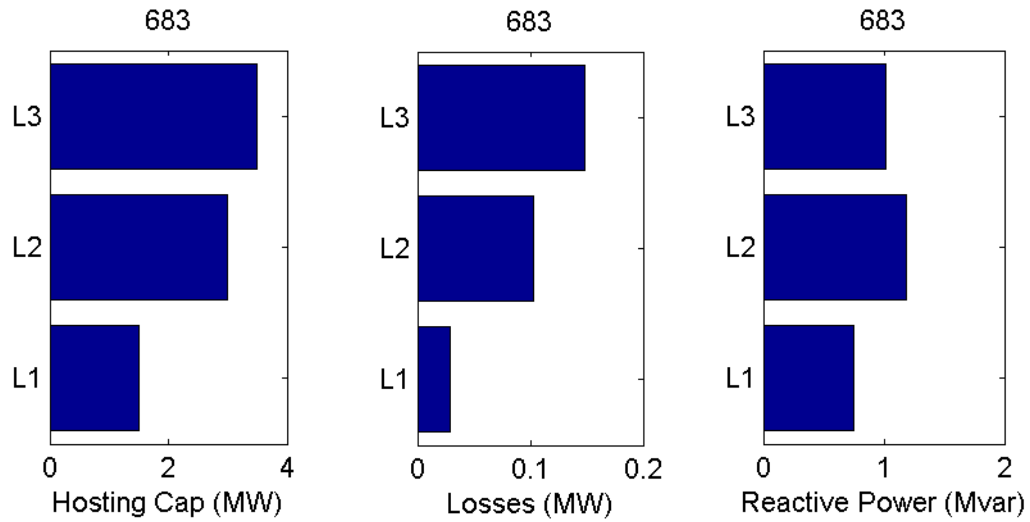
Possible violations based upon size/location

Observable violations occur regardless of size/location

Feeder Response

- Feeder response based on hosting capacity analysis
  - Thousands of PV scenarios converted from unity power factor for each of the settings/methods derived
- Median hosting capacity used to compare settings/methods
  - Quantified by advanced inverter setting result minus result from unity power factor

L1: Simple
L2: Moderate
L3: Complex



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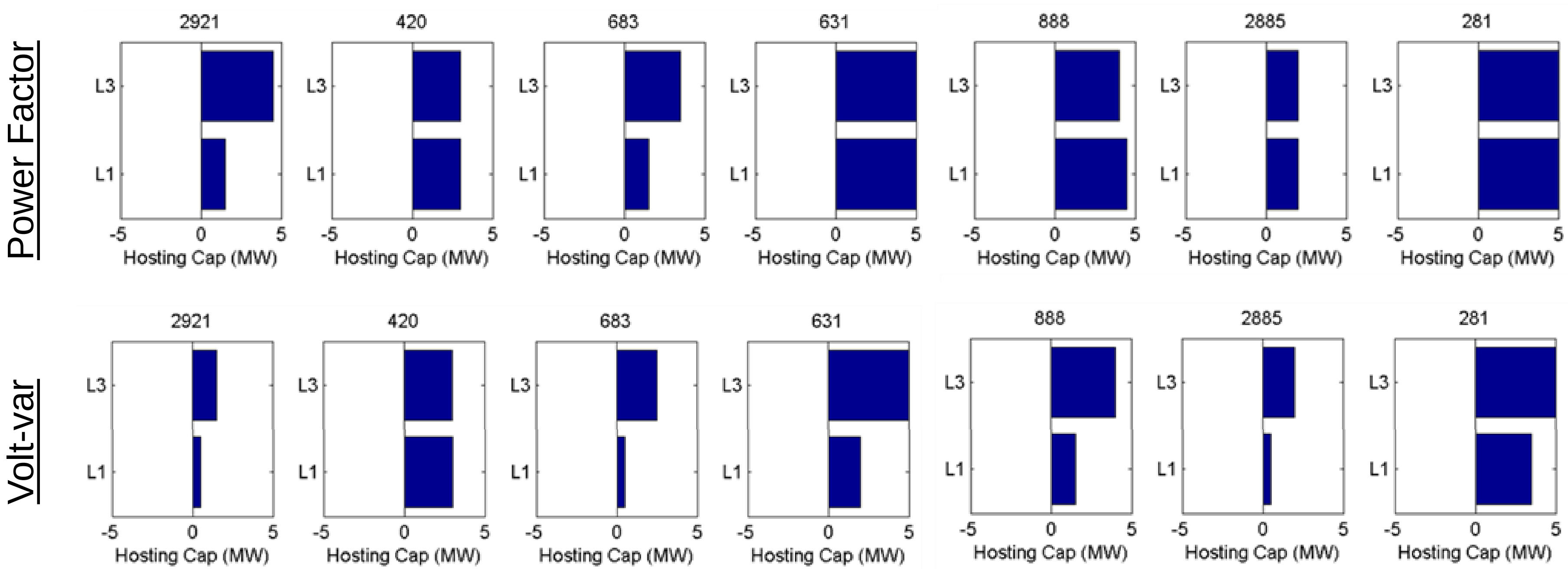
Comparison of Hosting Capacity Benefit

- Overall positive impact across all control types and settings
  – Level 3 power factor and Level 3 volt-var similar and perhaps best
  – Level 1 power factor does quite well despite simplicity
  – Level 1 volt-var at times just as good as the rest



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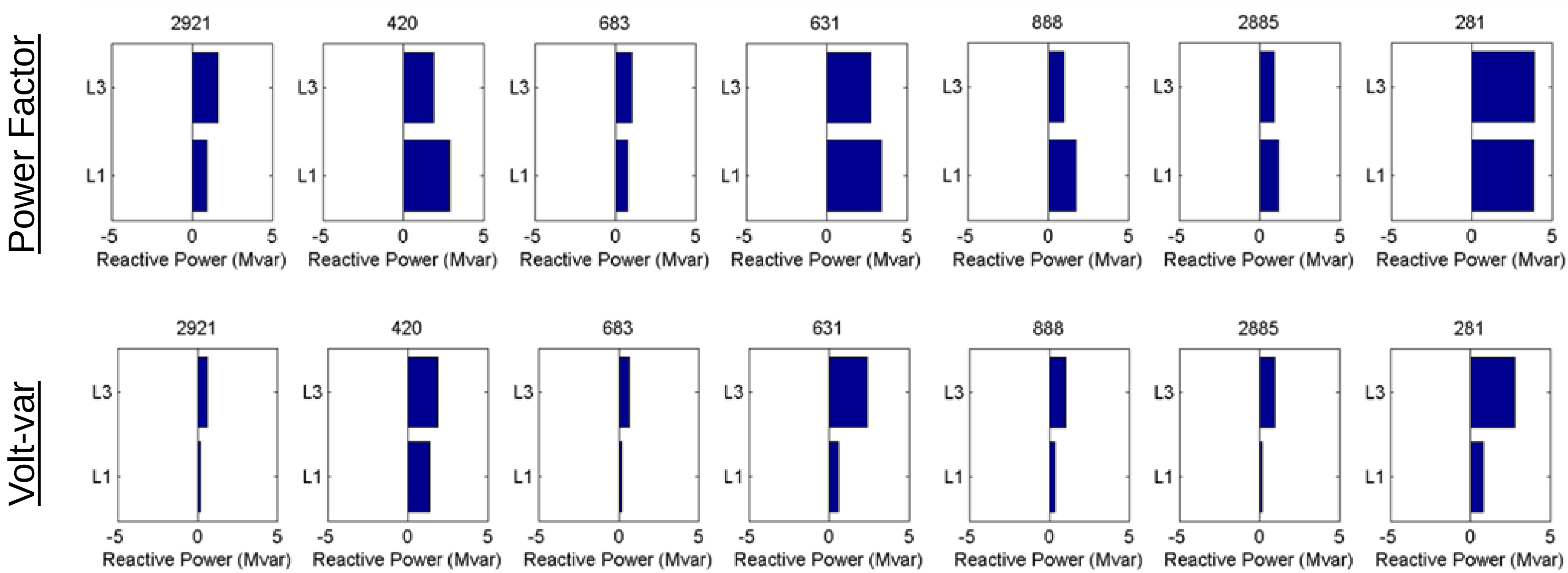
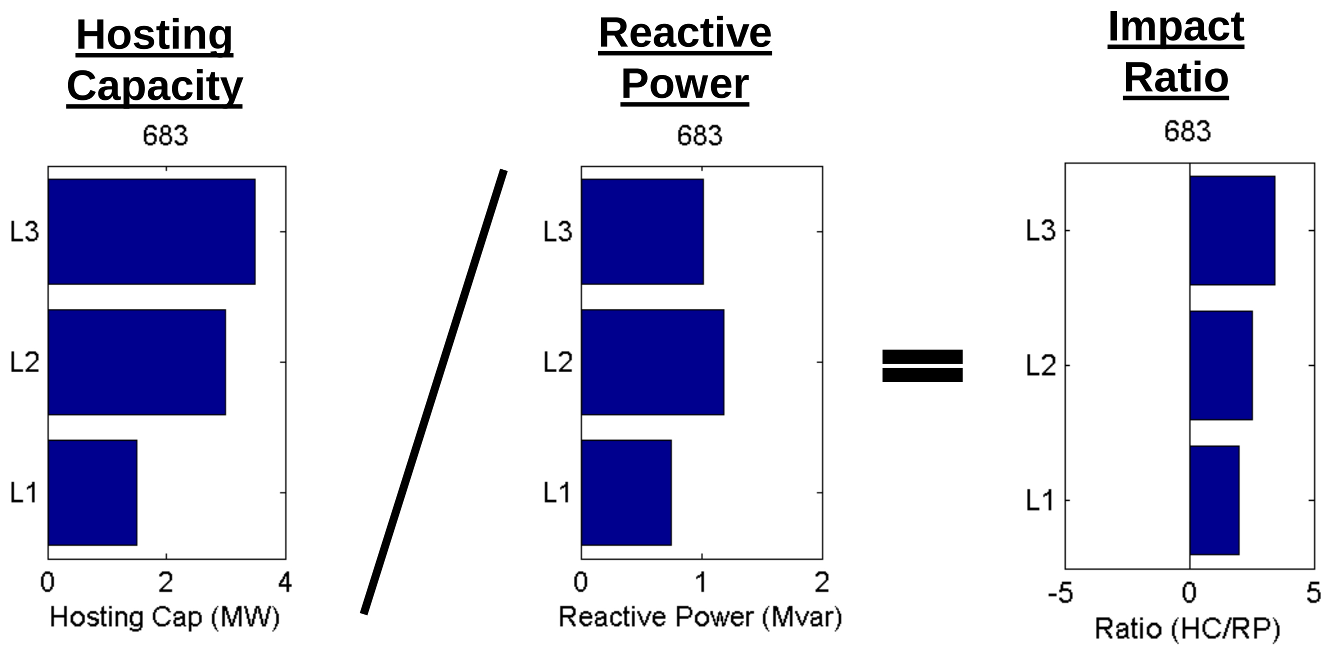
Comparison of Reactive Power Impact

- Overall reactive power demand increases across all control types and settings
  – Level 1 power factor generally highest due to un-tuned setting
  – Level 1 volt-var creates the least reactive demand



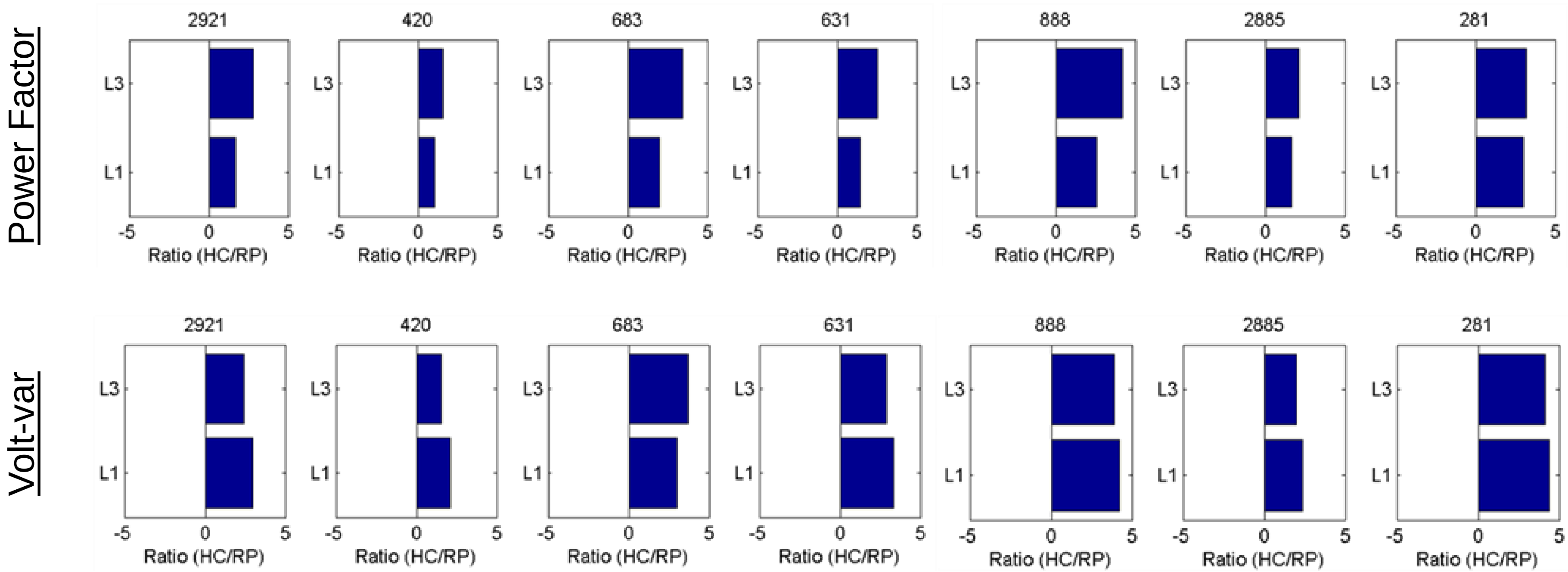
Quantifying Overall Impact from the Method/Setting

- Overall feeder impact is quantified by:
  - Hosting Capacity
  - Reactive Power
  - Losses (observed negligible)



Comparison of Overall Impact

- Level 1 volt-var is generally the most effective using reactive power to increase hosting capacity
  – Level 1 happens to be the most simplistic setting



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Summary

- Power factor and volt-var Level 3
  - Provides the most improvement to hosting capacity
- Volt-var Level 1
  - Improves hosting capacity
  - Least complex
  - Has one of the most effective uses of reactive power
- Volt-watt Level 1
  - Should be used in conjunction with power factor or volt-var control
  - Use reactive power control before curtailment

Inverter Settings for the Transmission System Performance

Outline

- Overview
- Study Method
- CMPLDWG Model
- PVD1 Model
- Feeder Impedances
- Results
- Conclusion

Overview

- WECC 2024 Heavy Summer case
- Focused on four operating areas in California
  - 46 GW of Load
  - 39 GW of Generation
- Study adds DER PV netted by load
  - 5,400 MW of DER PV
  - 10.5% penetration on load base
- Time domain simulations
  - Stability, Positive-sequence type
  - Two approaches to model DER PV

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Key research objectives

- Verifying reliability of new CA Rule 21 voltage and frequency ride-through.

Table Hh-1: Voltage Ride-Through Table

Region	Voltage at Point of Common Coupling (% Nominal Voltage)	Ride-Through Until	Operating Mode	Maximum Trip Time
High Voltage 2 (HV2)	V ≥120			0.16 sec.
High Voltage 1 (HV1)	110 < V < 120	12 sec.	Momentary Cessation	13 sec.
Near Nominal (NN)	88 ≤ V ≤ 110	Indefinite	Continuous Operation	Not Applicable
Low Voltage 1 (LV1)	70 ≤ V < 88	20 sec.	Mandatory Operation	21 sec.
Low Voltage 2 (LV2)	50 ≤ V < 70	10 sec.	Mandatory Operation	11 sec.
Low Voltage 3 (LV3)	V < 50	1 sec	Momentary Cessation	1.5 sec.

Table Hh-2: Frequency Ride-Through Table

System Frequency	Minimum Range of Adjustability (Hz)	Ride-Through Until (s)	Ride-Through Operational Mode	Trip Time (s)
f > 62	62 – 64	No Ride Through	Not Applicable	0.16
60.5 < f < 62	60.1 – 62	299	Mandatory Operation	300
58.5 < f < 60.5	Not Applicable	Indefinite	Continuous Operation	Not Applicable
57.0 < f < 58.5	57 – 59.9	299	Mandatory Operation	300
f < 57.0	53 – 57	No Ride Through	Not Applicable	0.16

- Investigating additional smart inverter functions like Dynamic Voltage Support.

High-level outcomes

- Voltage performance with new CA Rule 21 ride-through parameters is improved
  - CA Rule 21 voltage ride-through requirements seem to adequately consider FIDVR events.
  - Potential exists to further utilize “smart-inverter” functionality

- Frequency performance with new CA Rule 21 ride-through parameters is improved
  - At current penetration levels, frequency response of DER is not significant enough to impact the stability
  - Smart inverter functionality will improve frequency response under high penetration

Study Method & Assumptions

Study Method

WECC 2024 Base Case – four operating regions in CA selected as study footprint

Load at CMPLDW nodes increased to accommodate 5,400 MW of DER PV

Generation outside of CA footprint increased to balance increased loading due to DER PV

Reactive power reserves and short-circuit current available in the CA footprint remains unchanged

CMPLDW model changed to CMPLDWG across the CA footprint

Time-domain simulations run with varying voltage and frequency trip settings

Study Cases

Base Case

- The WECC 2024 Heavy Summer Case with no DER PV

IEEE Std. 1547-2003 Parameters

- The WECC 2024 Heavy Summer case with 5,400 MW of DER PV. The PV was modeled using the voltage and frequency trip parameters recommended by the IEEE 1547-2003 standard.

CA Rule 21 Parameters

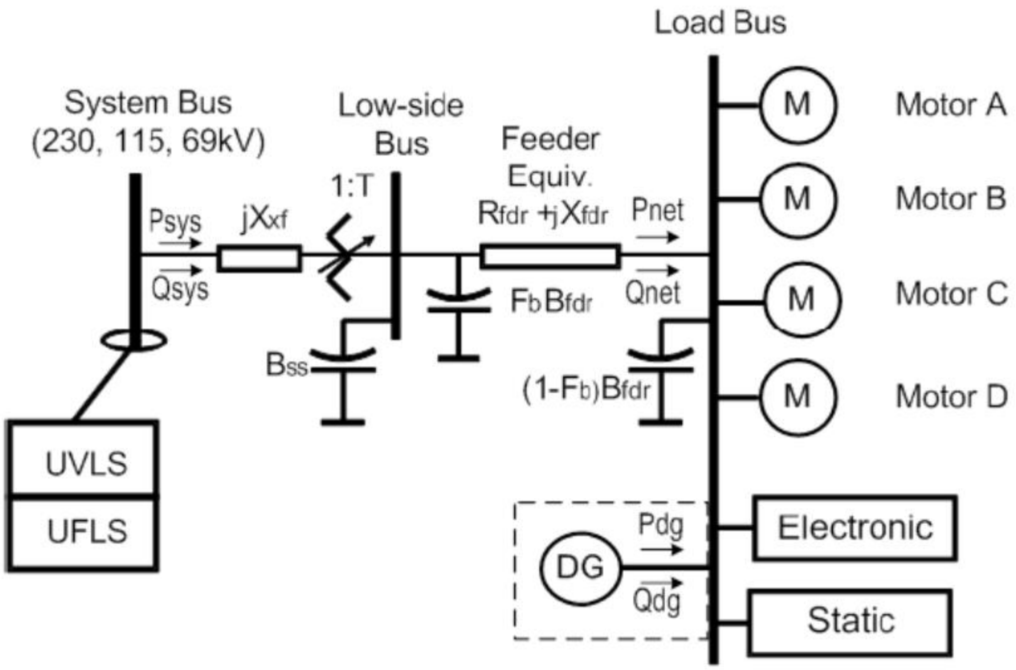
- The WECC 2024 Heavy Summer case with 5,400 MW of DER PV. The PV was modeled using the modified CA Rule 21 parameters for voltage and frequency ride-through.

PVD1 Case

- The WECC 2024 Heavy Summer case with 5,400 MW of DER PV. The PV was modeled using the modified parameters and operated in Q priority mode.

The CMPLDWG Model

- DER PV was added to the existing CMPDLW nodes
  - ***NO*** dynamic VAR control in this model
- Added in proportion to the existing load at the bus
- Remaining parameters of the CMPLDW model remained unchanged
  - Motor models will show impacts of FIDVR



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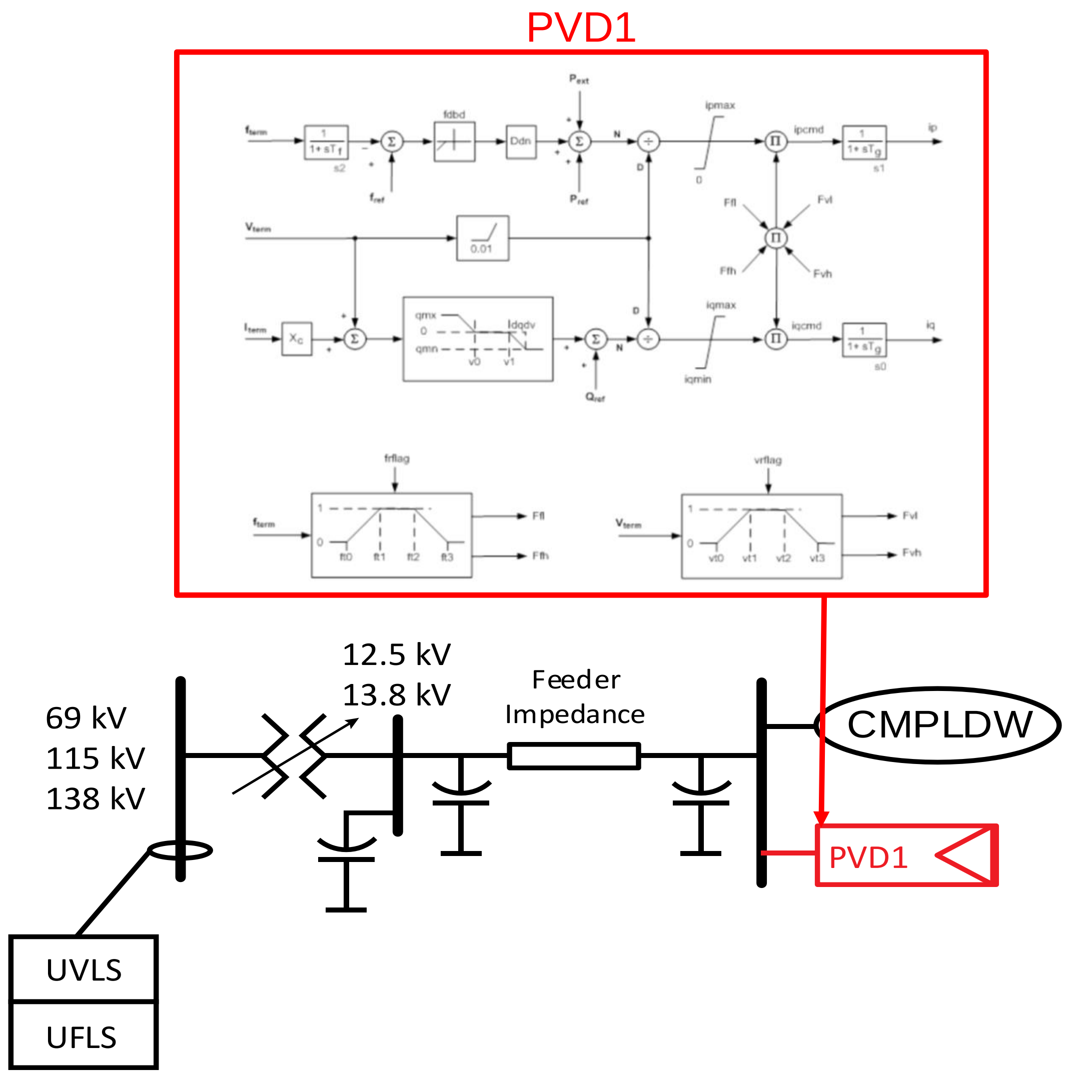
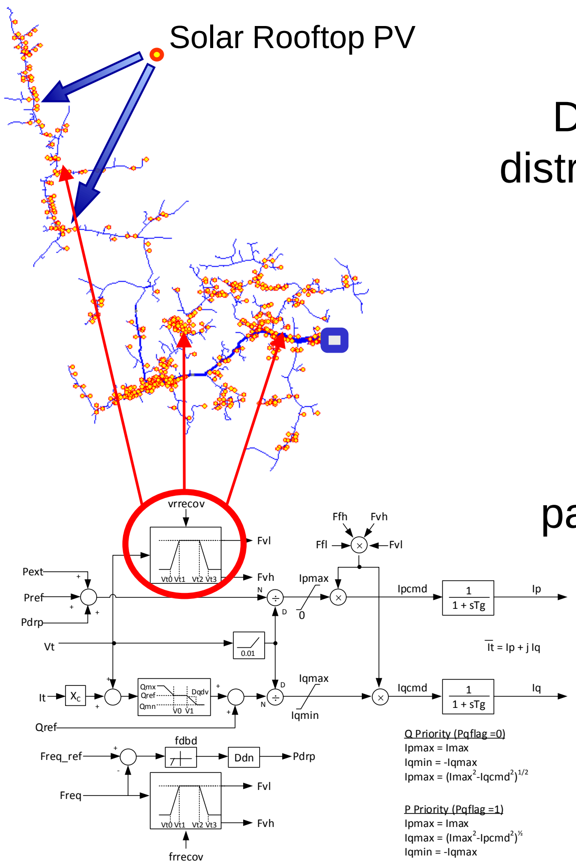
The PVD1 Model

- Generator and equivalent circuit explicitly modeled in power flow case
- X_{xf} (transformer impedance), R_{eq} and X_{eq} (equivalent feeder) modeled as short-circuits
- Circuit modeled **at four nodes** in the power case
  - Susceptible to FIDVR
  - Based on discussions with an IOU

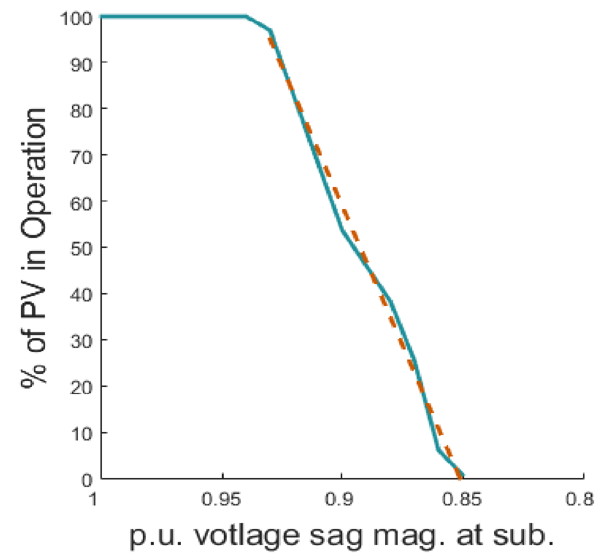


PVD1 Model Parameters

Tuning and optimization of PVD1 parameters Vt0, Vt1, Vt2, Vt3.



Detailed OpenDSS distribution feeder modeling **(NREL)**



Tuning of PVD1 parameters Vt0, Vt1 for bulk system studies **(EPRI)**

	Vt0	Vt1
CSI4 example Feeder I	~0.85 pu	~0.94 pu
WECC default settings	0.88 pu	0.90 pu

Source: EPRI figure based on [4] WECC Renewable Energy Modeling Task Force. *WECC Solar Power Plant Dynamic Modeling Guidelines.* Western Electricity Coordinating Council: April 2014.

Source: EPRI/NREL CSI 4 Task 4 (bulk system aspect) preliminary results, April 2016

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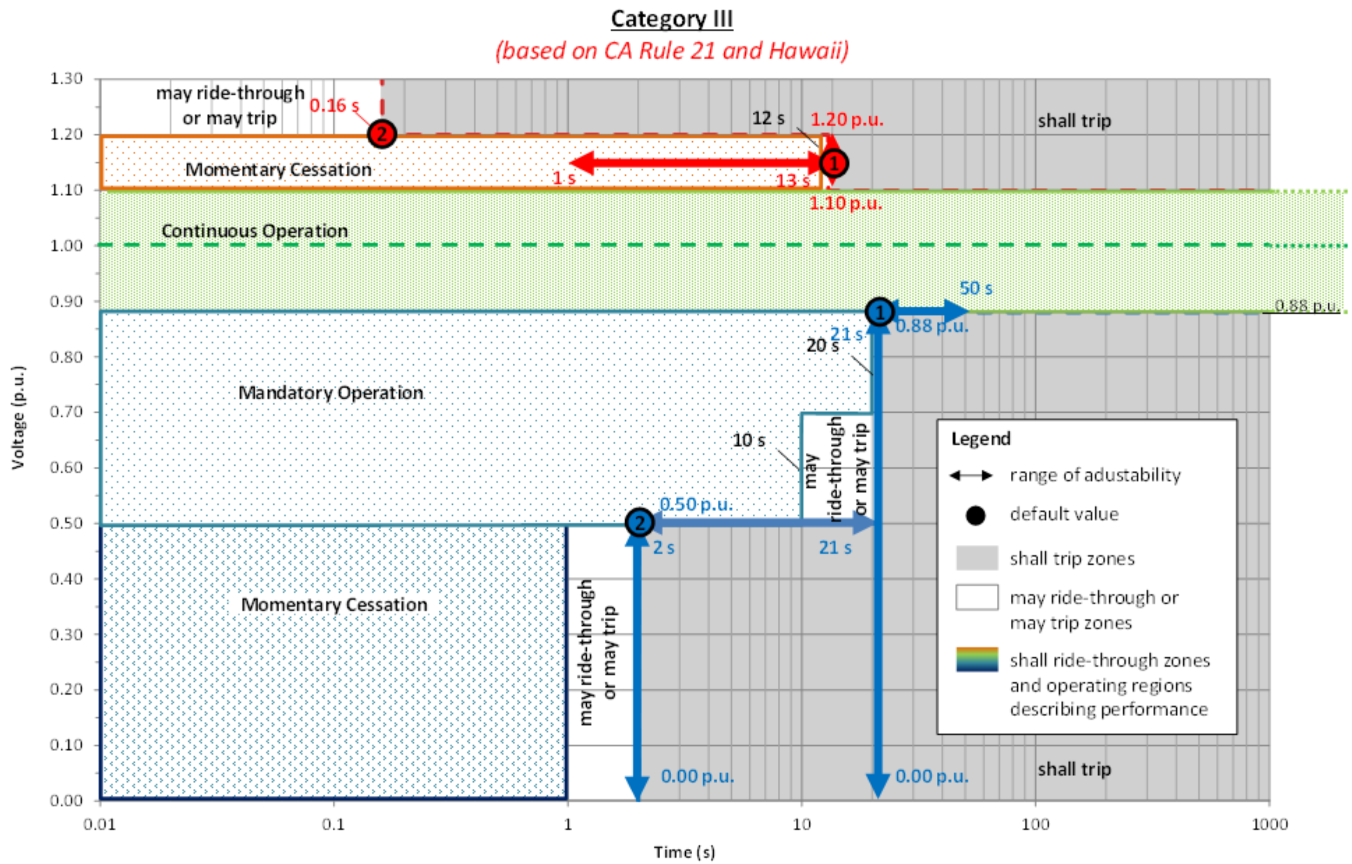
Results

CA Rule 21 Voltage Ride-Through & Trip



CA Rule 21 **voltage ride-through** requirements seem to adequately consider FIDVR events

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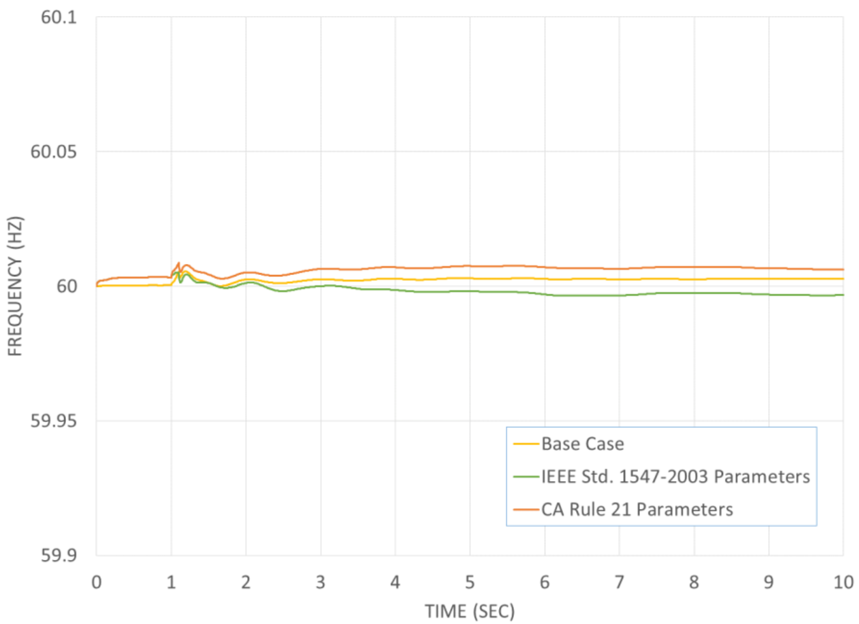
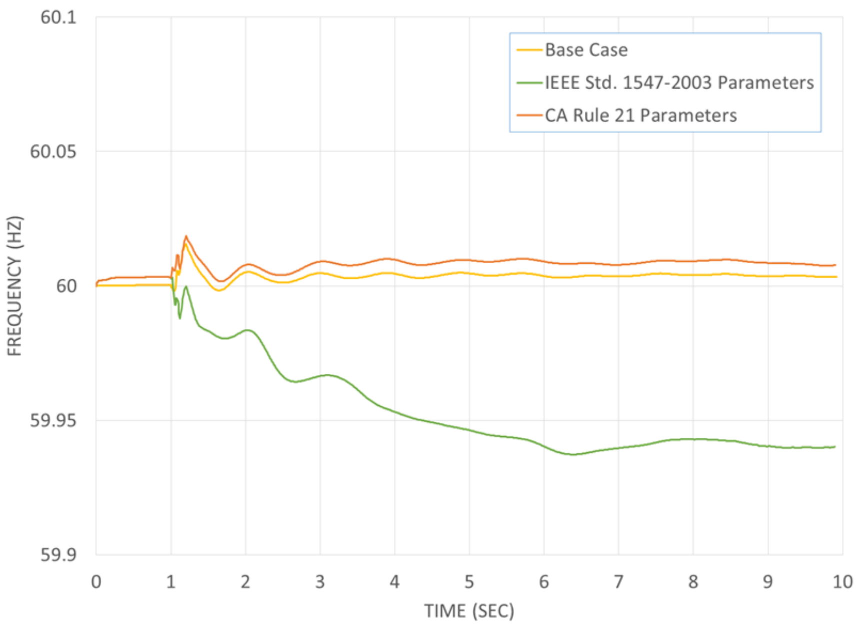
Results

CMPLDWG Model - Frequency

1-Phase to Ground Fault



3-Phase to Ground Fault



Frequency performance with new CA Rule 21 **voltage ride-through** parameters better than with IEEE Std. 1547-2003 parameters

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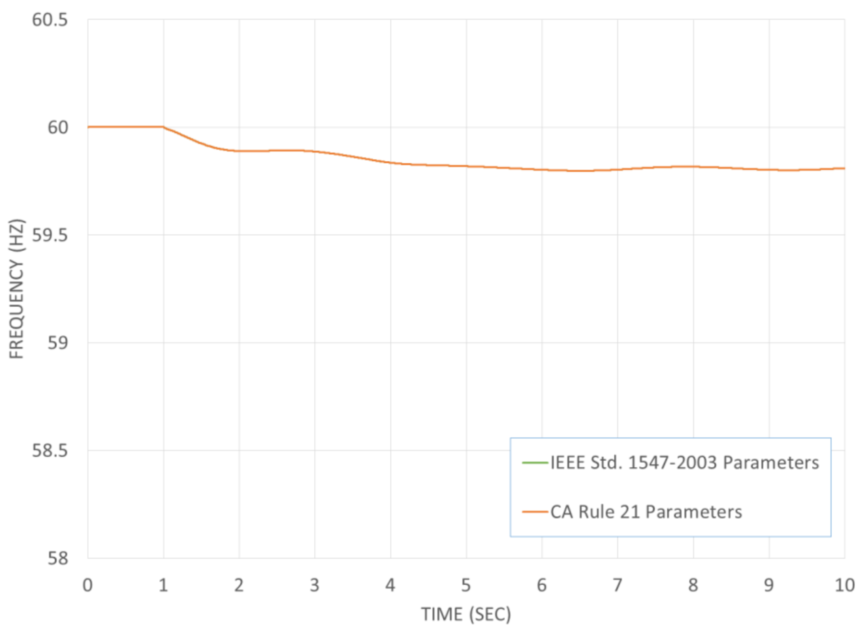
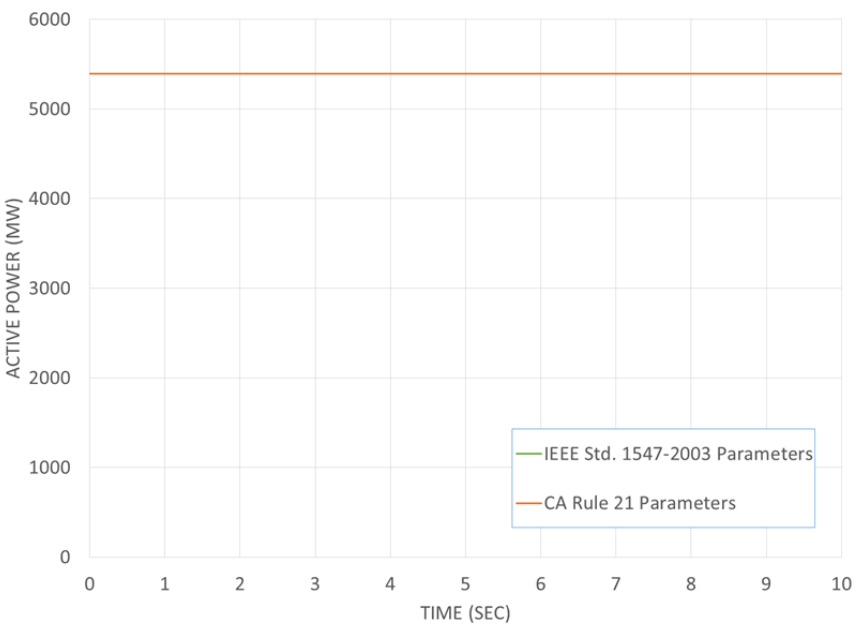
Results

CMPLDWG Model - Loss of Generation Contingency

Average Bus Frequency



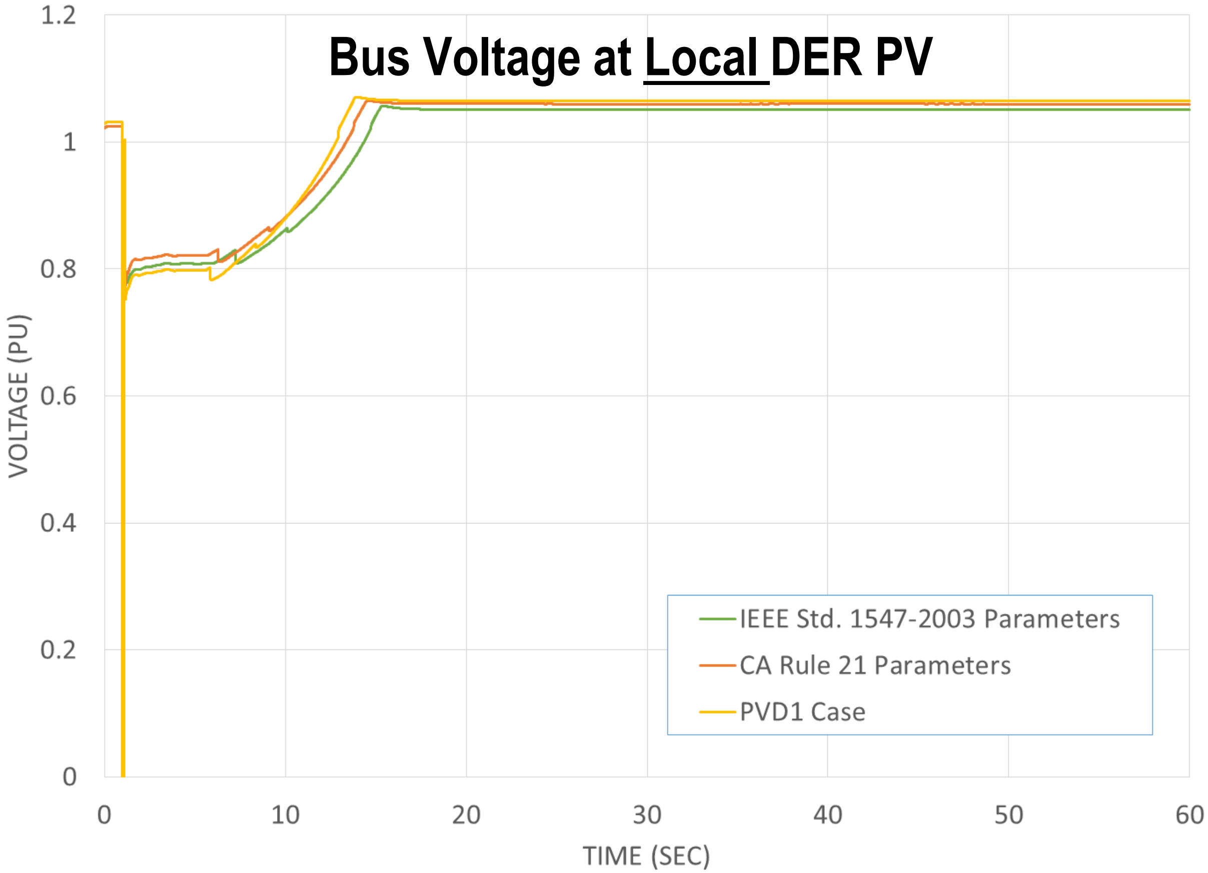
Active Power response from DER PV



No significant frequency impacts for neither the IEEE Std. 1547-2003 Parameters nor the new CA Rule 21 Parameters

Results

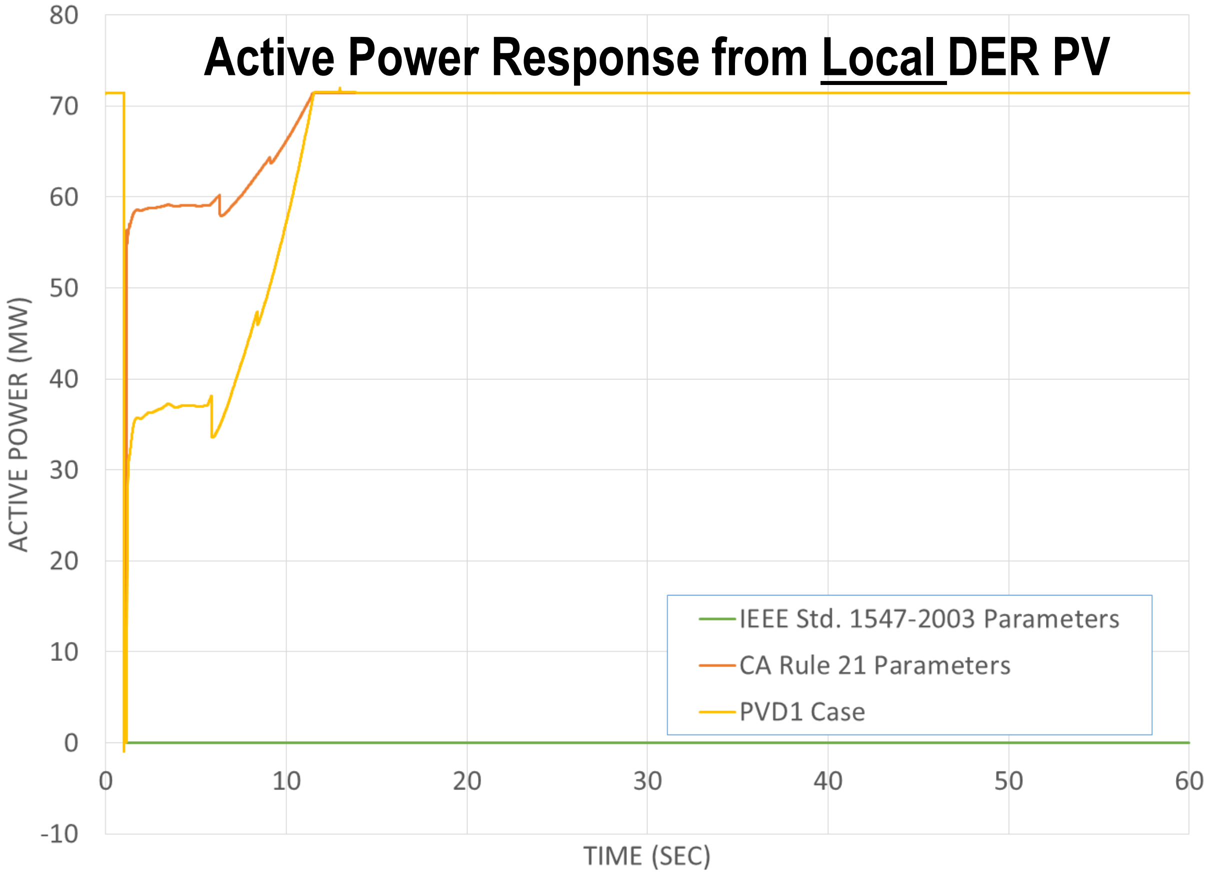
PVD1 Model – Three Phase to Ground Fault



Further stability improvements seem to exist when utilizing Dynamic Voltage Support

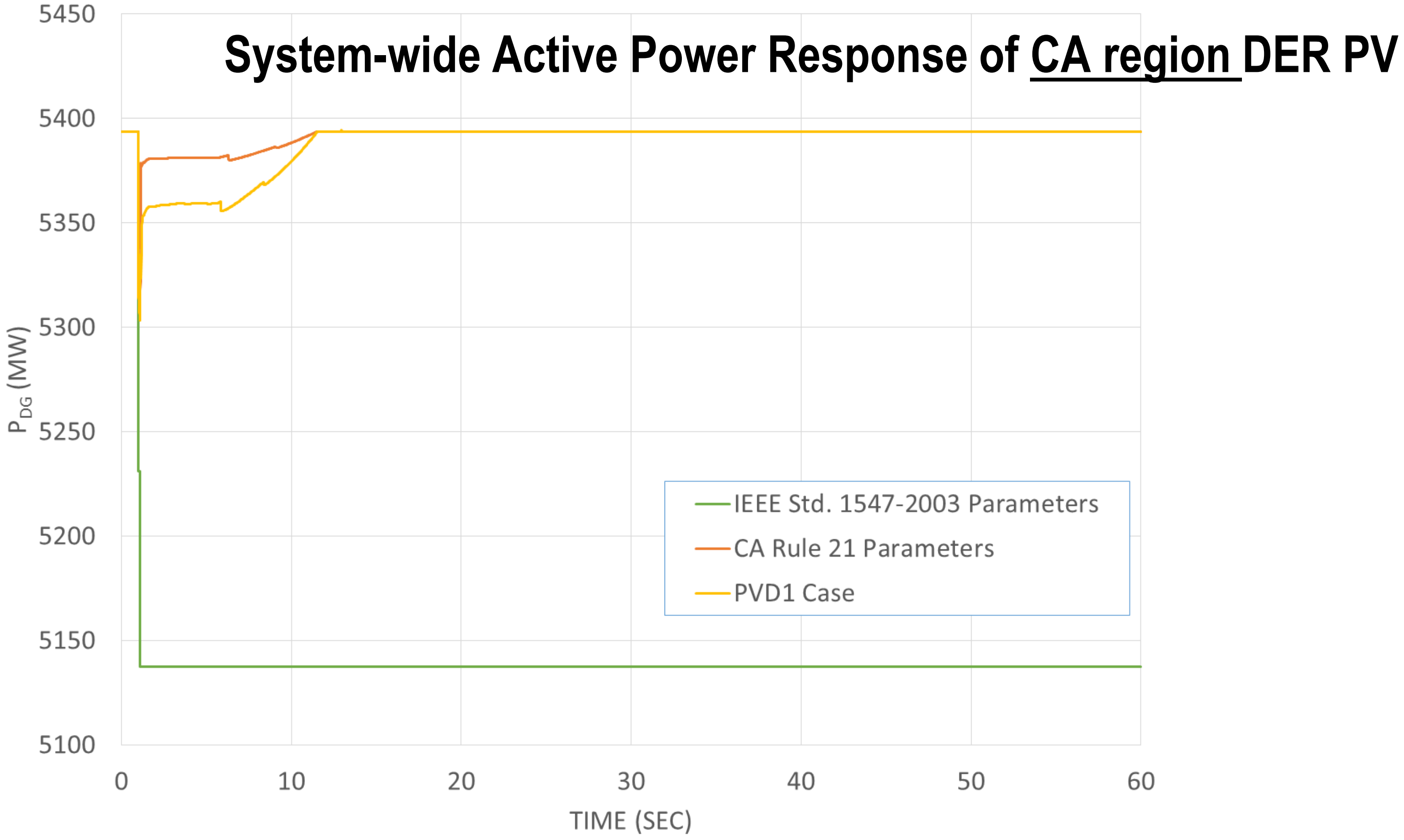
Results

PVD1 Model – Three Phase to Ground Fault



Results

PVD1 Model – Three Phase to Ground Fault



Specifications have to be system-dependent
(is active or reactive response more important?)

Summary

- No serious stability issues with a relatively low penetration of DER PV of 10.5%
- New CA Rule 21 voltage ride-through beneficial to voltage stability of the system
- New CA Rule 21 frequency ride-through seem to be very robust
  - Frequency response from DER PV cannot be adequately assessed with the WECC 2024 Heavy Summer Case
- Further stability improvements seem to exist when utilizing advanced smart-inverter functionality like Dynamic Voltage Support and Frequency Response
  - Specifications will be system-dependent (is active or reactive response more important?)
- Modeling approach and assumptions are key
- More detailed analysis needed to fully assess the capability of DER PV to support system stability dynamically

Conclusions

- Distribution focus
  - Methods to determine advanced inverter functions provided based on the tools/data available
  - Some settings work better than others based on
    - Increasing hosting capacity
    - Demanding reactive power

- Transmission focus
  - No serious stability issues with a relatively low penetration of DER PV of 10.5% in a WECC 2014 Heavy Summer case
  - New CA Rule 21 voltage and frequency ride-through improve system reliability
  - Further stability improvements seem to exist when utilizing advanced smart-inverter functionality
  - More detailed analysis needed to fully assess the capability of DER PV to support system stability dynamically

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http://calsolarresearch.ca.gov/funded-projects/110-analysis-to-inform-california-grid-integration-rules-for-pv

Analysis to Inform CA Grid Integration: Methods and Default Settings to Effectively Use Smart Inverter Functions in the Distribution System. EPRI, Palo Alto, CA: 2015. 3002007139.

Alternatives to the 15% Rule: Modeling and Hosting Capacity Analysis of 16 Feeders. EPRI, Palo Alto, CA: 2015. 3002005812.

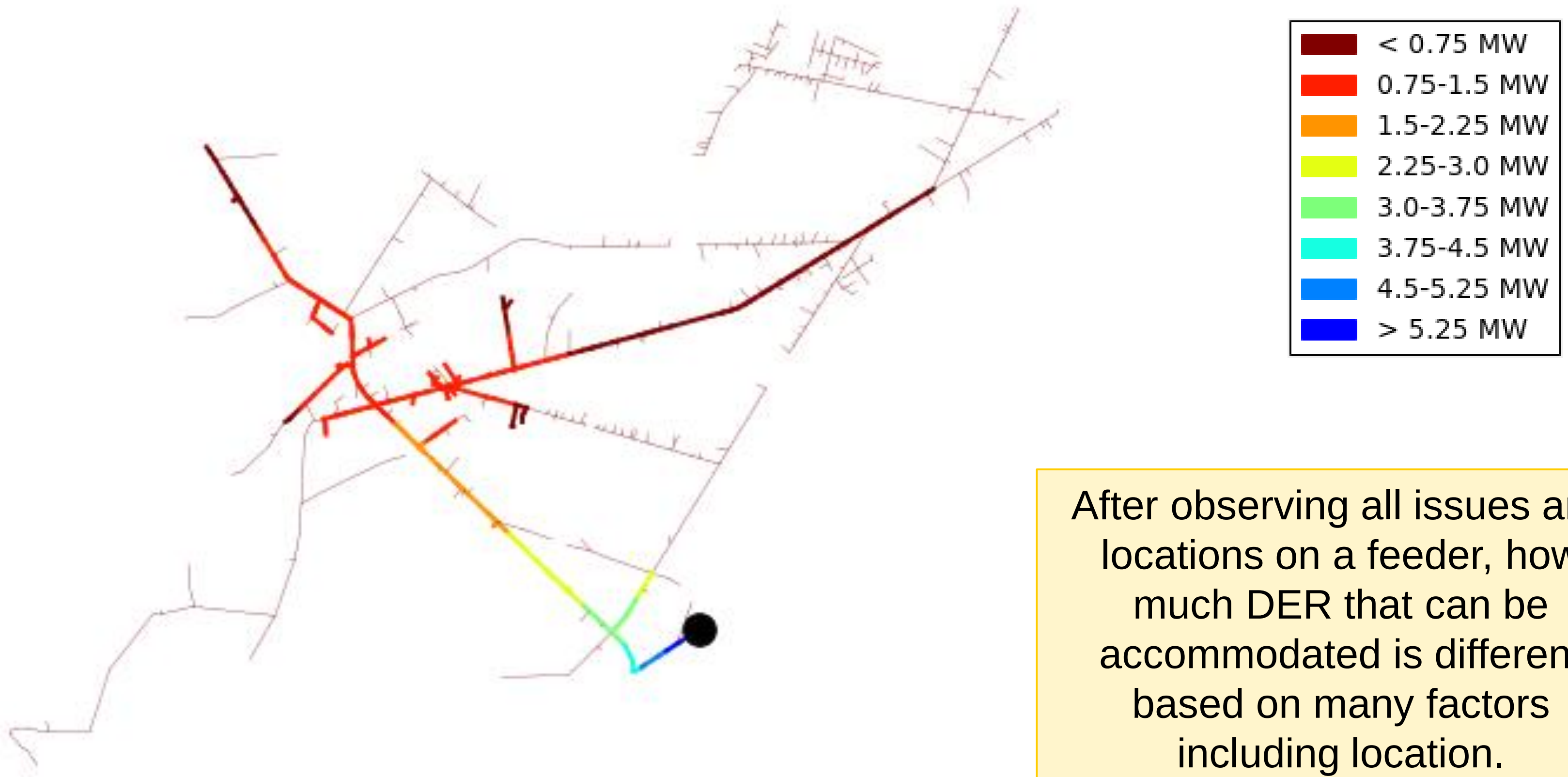
Alternatives to the 15% Rule: Final Project Summary. EPRI, Palo Alto, CA: 2015. 3002006594.

Appendix A

Inverter Settings for Distribution System Performance

What is Hosting Capacity?

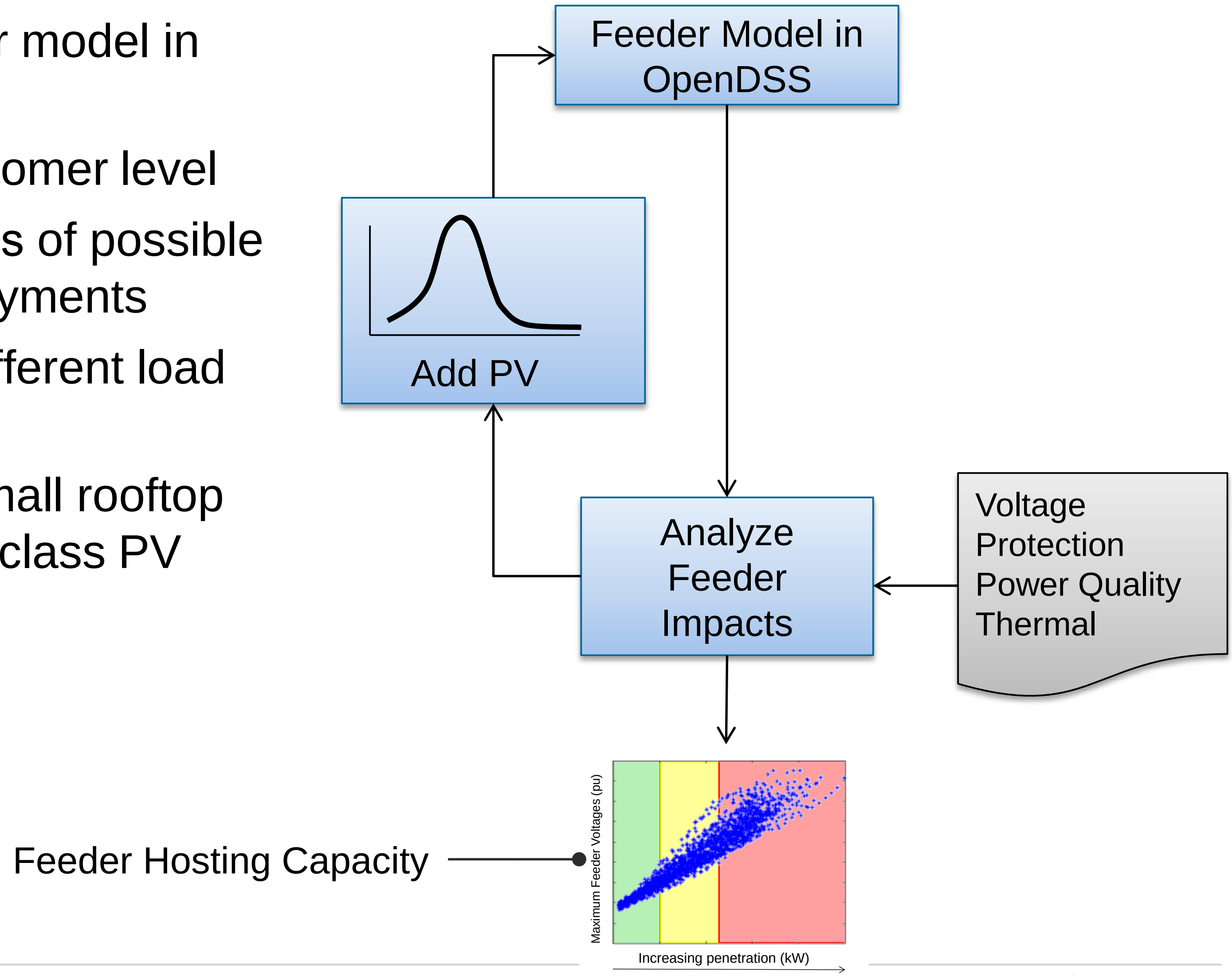
Amount of DER that can be accommodated on a given feeder without impacting reliability or power quality.



After observing all issues and locations on a feeder, how much DER that can be accommodated is different based on many factors including location.

How we Calculate Hosting Capacity in this Project

- Detailed feeder model in OpenDSS
- Add PV at customer level
- Evaluate 1000's of possible solar PV deployments
- Considering different load levels
- Considering small rooftop and large MW-class PV



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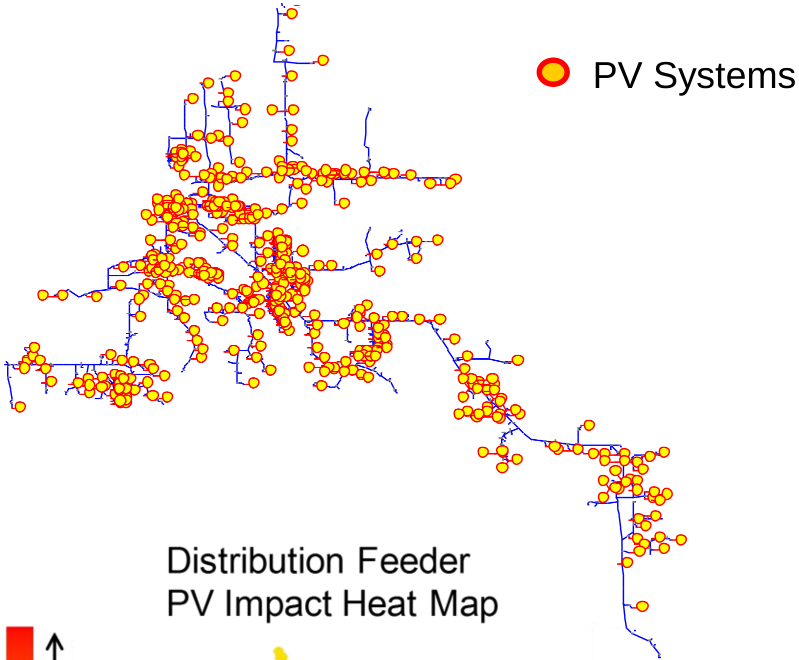
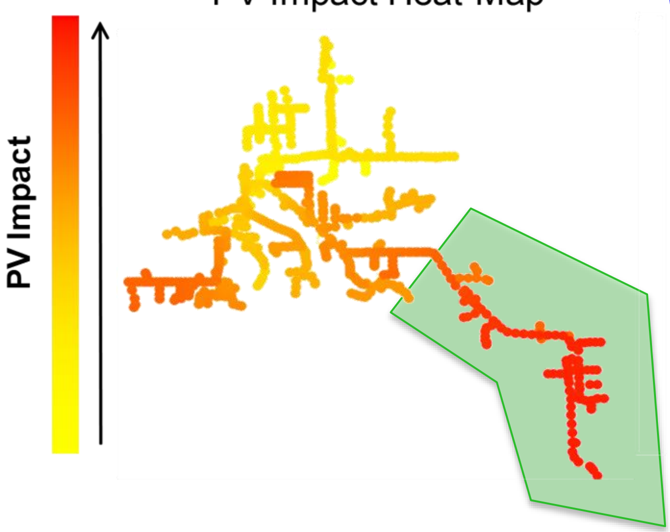
Stochastic Analysis



Distribution Feeder
PV Impact Heat Map



Baseline – No PV

PV Penetration 1

PV Penetration 2

PV Penetration 3

Beyond…

Process is repeated 100's of times to capture many possible scenarios

Increase Penetration Levels Until Violations Occur

- voltage
- protection
- power quality
- thermal

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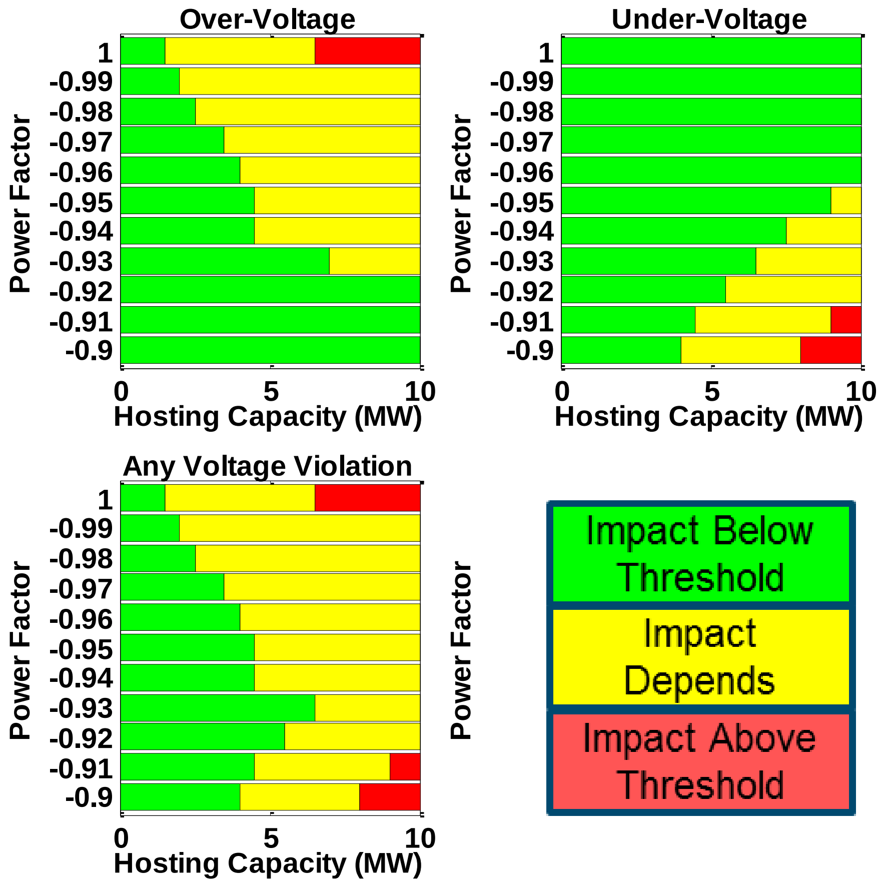
Finding the Optimal Inverter Setting

- Brute force analysis shows there may exist an optimal setting
  - On some feeders any setting may provide benefit
  - On other feeders some settings can show negative impact



Challenge with Defining Settings

- There is no single "optimal" setting for all feeders
- The "optimal" settings are as unique as the feeders the inverters are connected to

Selected Distribution Feeder Details

Feeder Name	Peak Load (MW)	Farthest 3-phase Bus (km)	PV Hosting Capacity	Nominal Voltage (kV)
683	3.6	17.9	Low	12
631	3.4	11.7	Moderate	12
888	2.2	2.8	Low	4
2885	9.2	11.9	Low	12
281	16.7	10.3	High	21
2921	6.4	15.5	Moderate	12
420	5.0	4.7	High	12

Appendix B

Inverter Settings for Transmission System Performance

Feeder Impedances (Example for California)

- Feeder Impedances based on a single-feeder
  - ~ 10 MVA per feeder
- Example: 100 MVA Load
  - Cluster 6: X = 0.005 pu, R = 0.0120
- **Using the default values from WECC dataset can lead to convergence issues in the power flow solution**

Cluster ID	kV	Z (pu)	X (pu)	R (pu)
4	12	0.29	0.13	0.25
6	20	0.13	0.05	0.12
8	4	0.68	0.33	0.59
7	12	0.11	0.06	0.10
8	12	0.39	0.19	0.34
1	12	0.41	0.21	0.35
2	12	0.29	0.15	0.25
Note: Per unit values are expressed on a 100 MVA base.				

DER PV Parameters

Parameter Description	IEEE 1547-2003 (CMPLDWG)	CA Rule 21 (CMPLDWG)	PVD1 CA Rule 21
Inverter current lag time constant	NA	NA	0.02
Apparent current limit	1.2	1.2	1.2
Priority to reactive current (0) or active current (1)	NA	NA	0
Voltage tripping is latching (0) or partially self-resetting (>0 and <=1)	0	1	1
Voltage tripping response curve point 0	0.88	0.50	0.85*
Voltage tripping response curve point 1	0.90	0.52	0.94*
Voltage tripping response curve point 2	1.10	1.19	1.19
Voltage tripping response curve point 3	1.20	1.21	1.21
Frequency tripping is latching (0) or partially self-resetting (>0 and <=1)	0	1	1
Frequency tripping response curve point 0	59.5	56.5	56.5
Frequency tripping response curve point 1	59.7	57	57
Frequency tripping response curve point 2	60.3	61.9	61.9
Frequency tripping response curve point 3	60.5	62.1	62.1

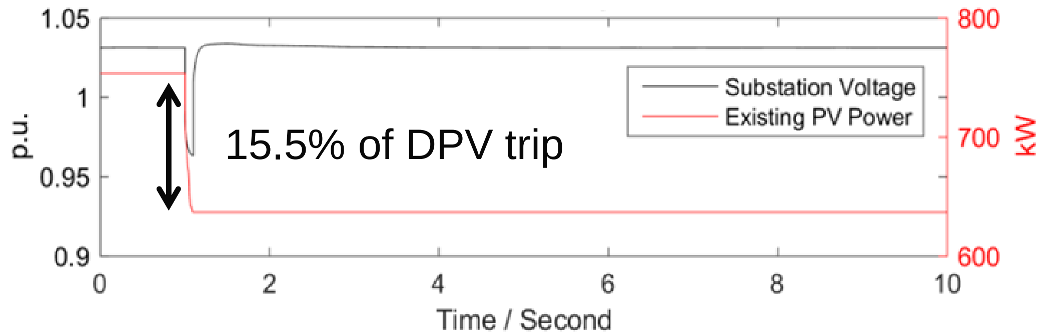
DER PV Parameters

Parameter Description	IEEE 1547-2003 (CMPLDWG)	CA Rule 21 (CMPLDWG)	PVD1 CA Rule 21
Lower limit of deadband for voltage droop response	NA	NA	0.98
Upper limit of deadband for voltage droop response	NA	NA	1.02
Voltage droop response characteristic	0	0.05	0.05
Down regulation droop gain	0	0.05	0.05
Overfrequency deadband for governor response	NA	NA	-0.2
Line drop compensation reactance	NA	NA	0
Minimum reactive power command	NA	NA	-0.44
Maximum reactive power command	NA	NA	-0.44
Frequency transducer time constant	0.05	0.05	0.05
Voltage limit used in the high voltage reactive power logic	1.2	1.2	1.2
High voltage point for low voltage active power logic	0.8	0.88	0.88
Low voltage point for low voltage active power logic	0.4	0.5	0.5
Limit in the high voltage reactive power logic	-1.3	-1.44	-1.44
Acceleration factor used in the high voltage reactive power logic	0	0.7	0.7

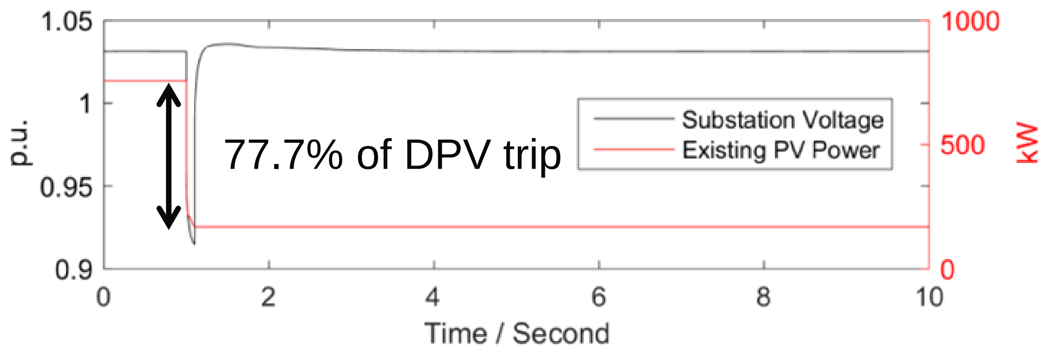
Evaluation of distribution-connected PV (DPV) Response

- Voltage sag wave shape supplied by PSLF simulation of a close-in temporary fault
- Distribution circuit (and DPV) response modeled in OpenDSS via quasi-static time-series (QSTS) simulation over 10 seconds
- Voltage diversity, seen at each DPV point of interconnection (POI), results in various percentages of DPV tripping off-line due to under-voltage (UV) settings (IEEE 1547-2003 default settings) for each voltage sag evaluated

$V_{sag} = 0.93\ V_{pu}$



$V_{sag} = 0.88\ V_{pu}$

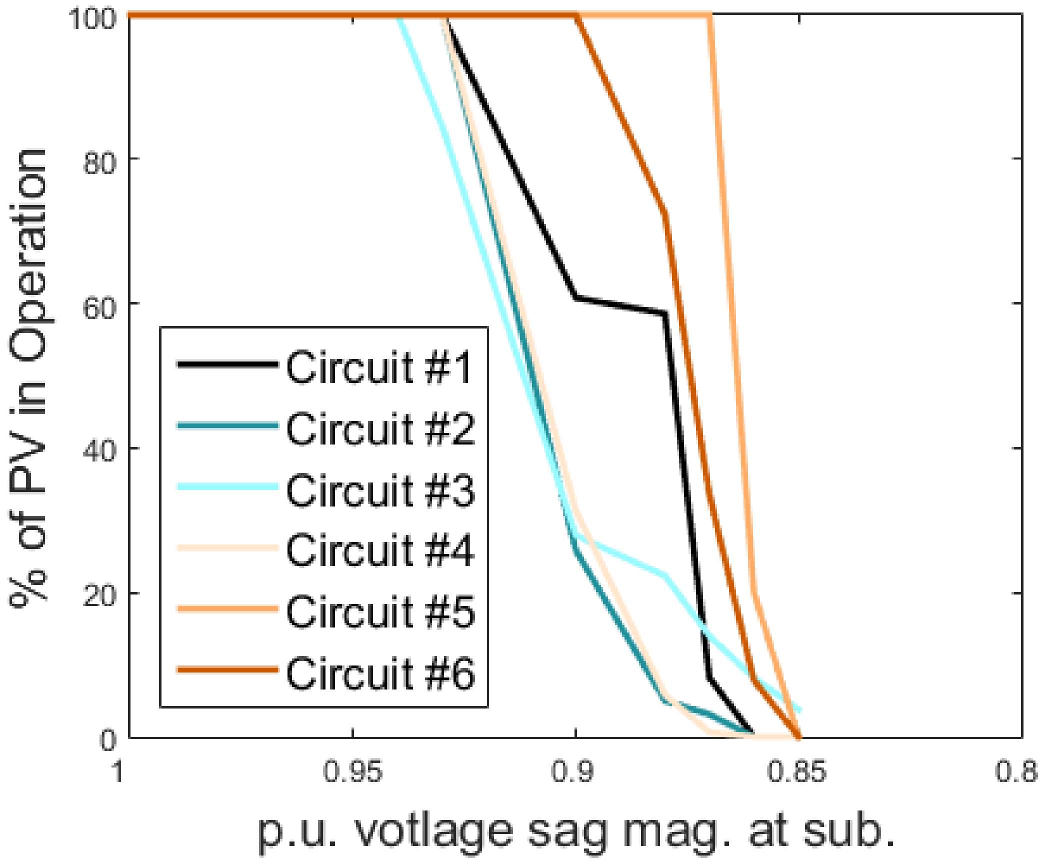


DPV tripped offline is 5 times higher at $V_{sag} = 0.88\ V_{pu}$ than at $0.93\ V_{pu}$ for this circuit

Source: NREL (2016)

Variation in DPV/Circuit Responses

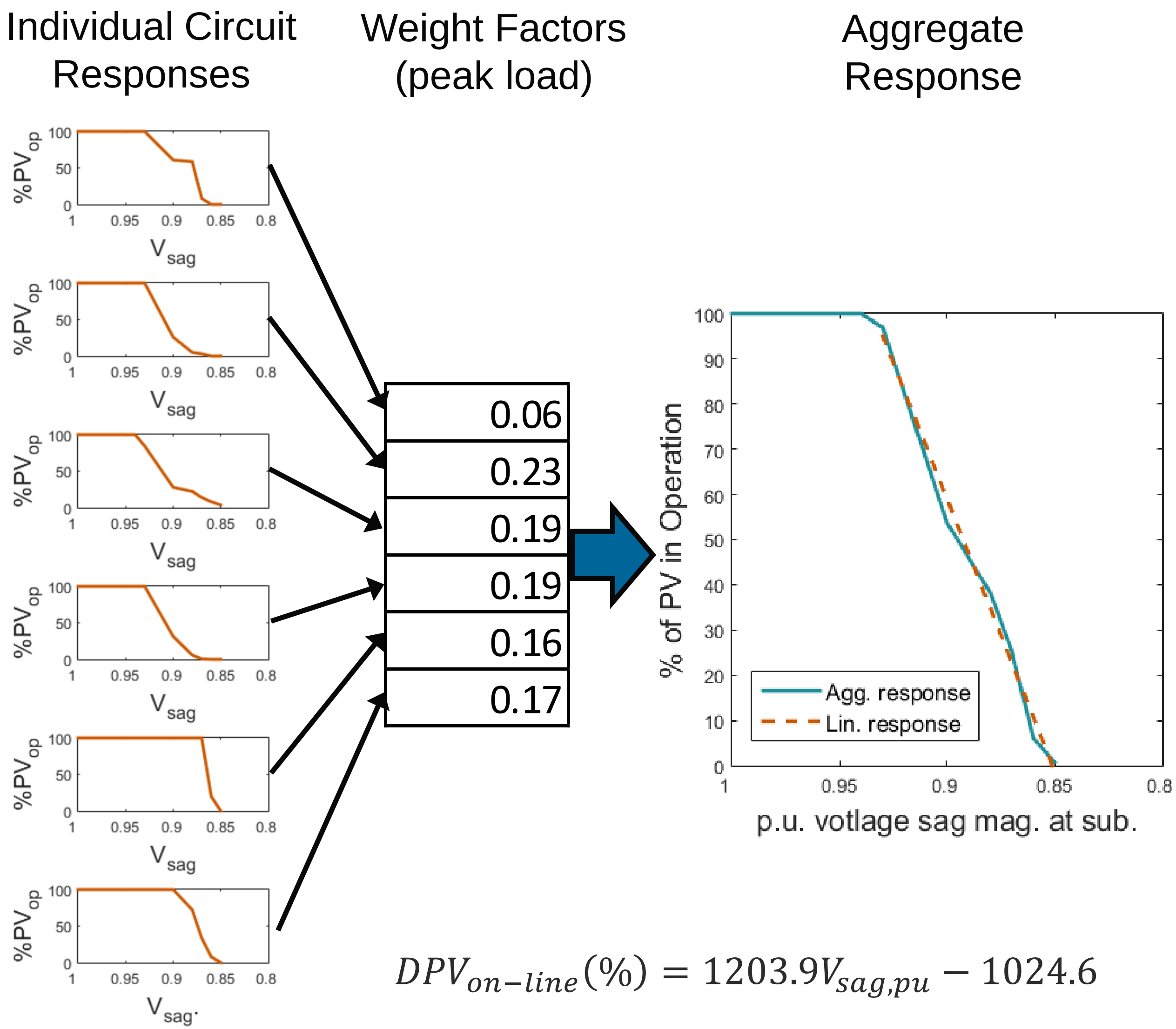
- Each circuit shows a unique response
- Variety of responses are due to the differing circuit characteristics and load / generation placement on the circuits
- DPV starts to trip offline at voltage sags of 0.94 – 0.87 V_{pu}
- In all cases, nearly all DPV is off-line by 0.85 V_{pu}



Source: NREL (2016)

Aggregation of Dist. Sys. Response

- The responses of the six circuits evaluated are weighted, for each V_{sag} magnitude investigated, by the peak loading of the distribution circuit
- Resulting aggregate response represents a distribution system & DPV response for a system comprised of equal distributions of the six evaluated circuits
- The aggregate response is linearized to determine the approximate response implementable in bulk system models



$$DPV_{on-line}(\%) = 1203.9V_{sag,pu} - 1024.6$$

Source: NREL (2016)

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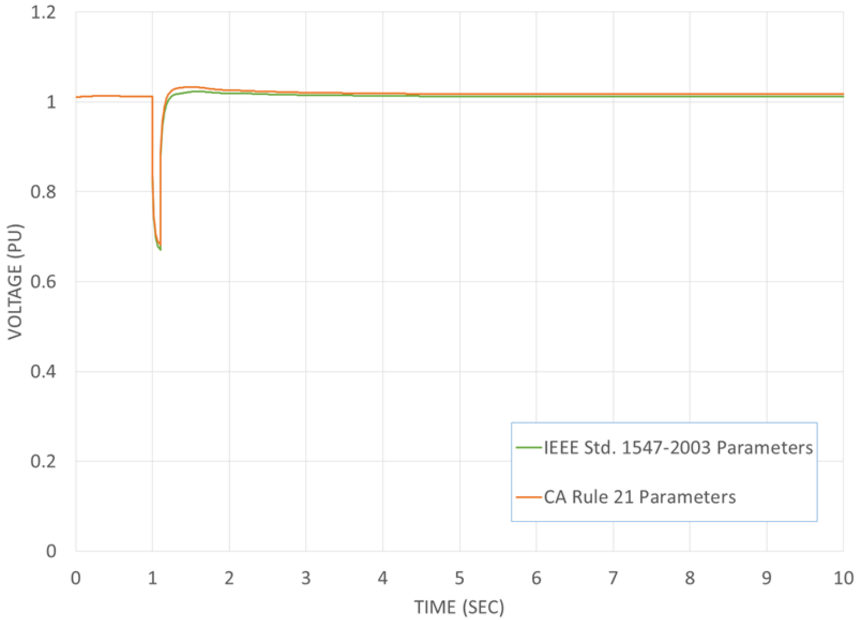
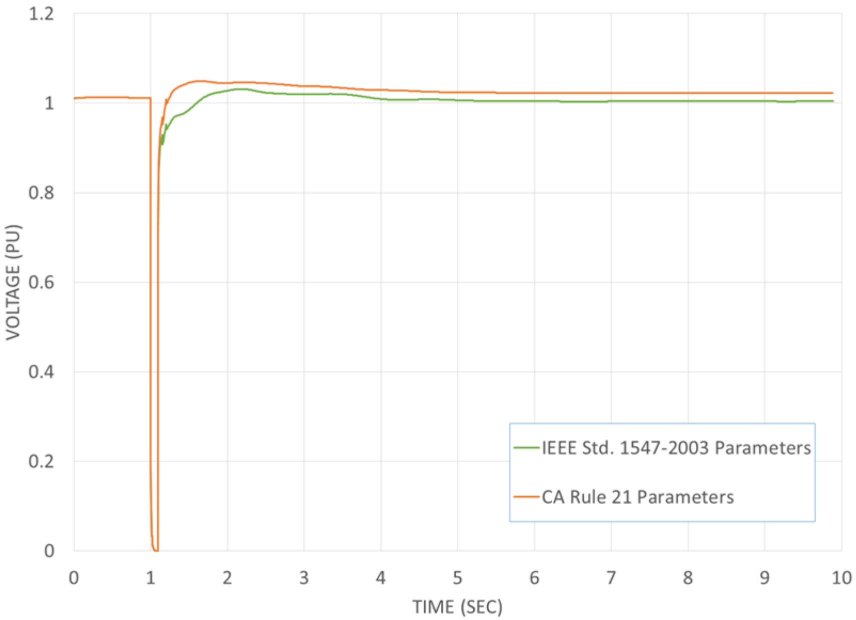
Results

CMPLDWG Model - Voltage

1-Phase to Ground Fault



3-Phase to Ground Fault

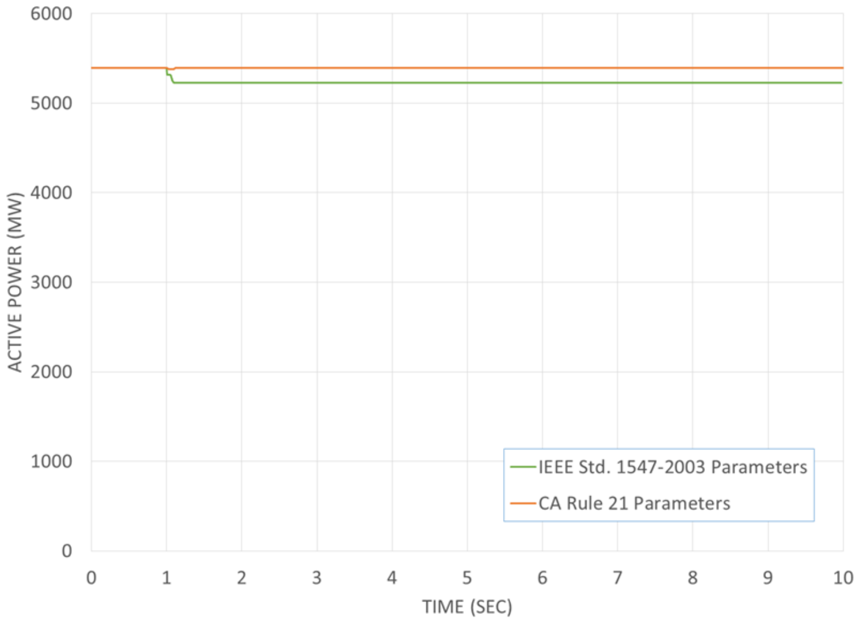


Voltage performance with new CA Rule 21 ride-through parameters better than with IEEE Std. 1547-2003 parameters.

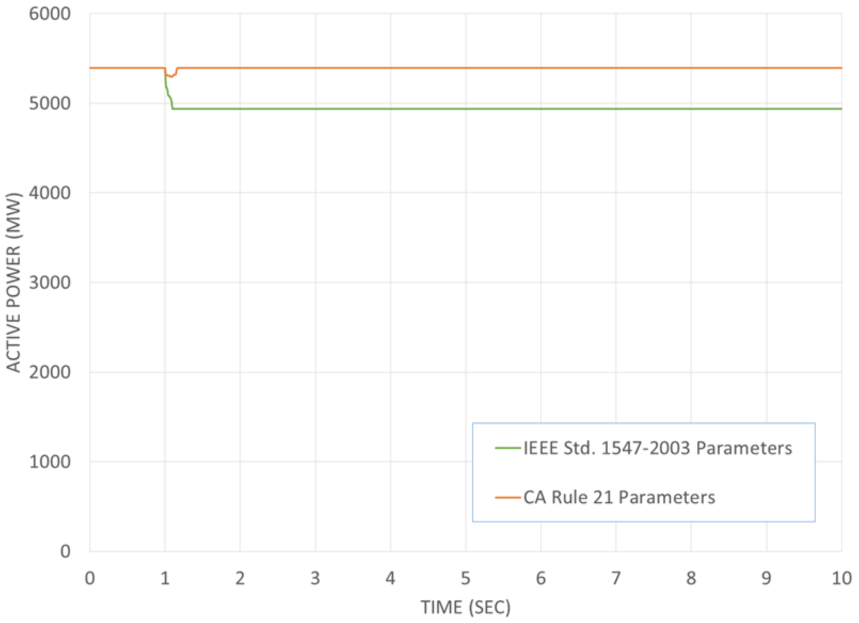
Results

CMPLDWG Model – Active power

1-Phase to Ground Fault



3-Phase to Ground Fault



Post-fault active power balance with CA Rule 21 ride-through parameters better than with IEEE Std. 1547-2003 parameters

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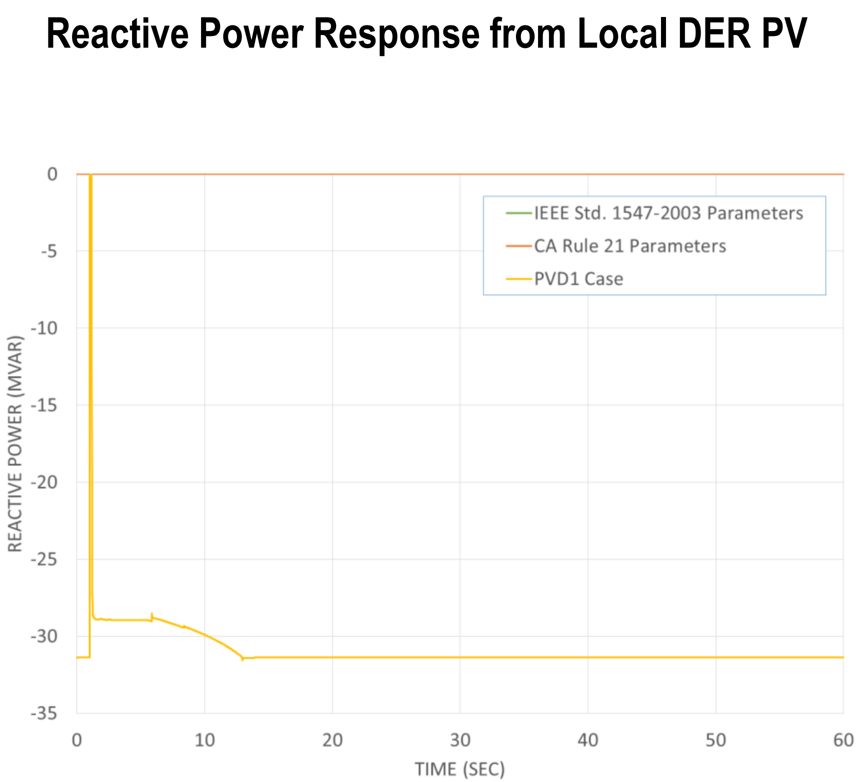
Results

PVD1 Model – Three Phase to Ground Fault



- IEEE Std. 1547-2003 Parameters and CA Rule 21 Parameters keep Q injection fixed at 0 MVAr
- PVD1 Case initially has Q at -31 MVAr
  - Operated in Q priority mode
  - Occurs in order to have the same V at the POI in the power flow solution
  - Reduces active power output during the fault and tries to increase reactive power injection during the FIDVR